

**COMMENTS ON AIR EMISSION REPORTS  
FOR  
THREE MAJOR AIR POLLUTANT EMITTING  
FACILITIES  
BAY COUNTY, FLORIDA**

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**MAY 14, 1999**

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Bay County, Florida**

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**Air Quality Branch, Fish and Wildlife Service – Denver  
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The Bay Environmental Study Team and the Florida Department of Environmental Protection has developed a management plan for the St. Andrew Bay Ecosystem (*A Look to the Future: A Management Plan for the St. Andrew Bay Ecosystem*). The plan notes that, in general, the St. Andrew Bay Ecosystem, located primarily in Bay County, Florida, is in satisfactory condition. In addition, "The drainage basin is not considered industrialized, so atmospheric deposition from local sources of the primary pollutants is not considered to be significant." However, the plan recognizes that the area is expected to experience a considerable increase in the rate of growth of the human population in the near future. As population increases, resultant air pollution emission increases from increased power production, automobiles, and other sources will cause increases in atmospheric deposition to the bay area. Therefore, it is important to develop a framework for understanding the types and amounts of atmospheric pollutants that are affecting the bay ecosystem and potential options for controlling these pollutants.

We have reviewed the air emissions reports for the three largest air pollutant emitting facilities in Bay County, Florida. These include Gulf Power Company's Lansing Smith Plant (Gulf Power-Smith), Bay County Energy Systems, Inc.'s Resource Recovery Facility (Bay County Energy), and Stone Container Corporation's Panama City Mill (Stone Container). All facilities are located either on the bay or within a mile or two of the bay. The following analysis does not attempt to determine if the three facilities are in compliance with State emission limits, as that analysis should be performed by the State permitting agency. Rather, the following analysis includes an estimate of the types and amounts of the pollutants likely to be emitted and an evaluation of the level of emission control used at each source. Unless otherwise noted, our emissions were based on the Environmental Protection Agency's (EPA) Compilation of Air Pollutant Emission Factors (AP-42), and may therefore differ from emissions calculated by the sources evaluated. Table 1.a summarizes the fuel consumption of the three facilities. Emissions were calculated from these estimates of fuel consumption and types and efficiencies of emissions controls. Because of the absence of information on gas flows, capacities, and control efficiencies, it was not possible to precisely estimate the potential for emission reductions in most cases.

### **Emissions Summaries**

#### **Criteria Pollutants**

Table 1.b summarizes the criteria pollutants, including total, inorganic, and organic particulate matter (PM), sulfur dioxide (SO<sub>2</sub>), and nitrogen oxides (NO<sub>x</sub>), emitted by the three facilities. As the table indicates, Gulf Power-Smith emits significant portions of the total PM (over 60%

of total), SO<sub>2</sub> (over 90% of total), and NO<sub>x</sub> (over 90% of total).

### Organic Emissions

Table 1.c shows that, of the three facilities, Bay County Energy emits the majority of dioxins and dibenzofurans. Stone Container emits the majority of polynuclear aromatic hydrocarbons. Gulf Power-Smith emits the majority of those compounds listed under "various organic compounds."

### Hydrogen Chloride, Fluorides, and Heavy Metals

Table 1.d summarizes emissions of hydrogen chloride (HCl), hydrogen fluoride (HF), and heavy metals, including antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, magnesium, manganese, mercury, nickel, and selenium, from the three facilities. Gulf Power-Smith and Bay County Energy each emit about half the total HCl (from the 3 facilities). Gulf Power-Smith emits the majority of HF (93%). And Gulf Power-Smith emits between 70-93 % of all metals except mercury. Gulf Power-Smith emits 56% of the total mercury; Bay County Energy emits 40% of the mercury.

### **Control Technologies**

#### Stone Container

*Bark Boiler #4* (Emission Unit ID #016) burns woodwaste that is inherently low in sulfur and ash. The wood fuel is supplemented by firing low-sulfur (1.07% S) coal, high sulfur (2.06% S) residual oil, and clean-burning natural gas. Particulate emissions are controlled by a low-efficiency (<80%) wet scrubber and gravity-settling chamber (<80%). Total Reduced Sulfur (TRS) emissions from the digesters may also be vented to this boiler for incineration. Emissions in 1997 were estimated by Stone Container at 1,575 tons per year (TPY) NO<sub>x</sub>, 0.513 TPY lead, 35 TPY fine particulate (PM<sub>10</sub>), and 1,230 TPY SO<sub>2</sub>. Our estimates of these pollutants are contained in Table 1 and Appendices 1 and 4.

NO<sub>x</sub> emissions could be reduced by approximately 40% (to around 0.1-0.2 lb/mmBtu) by addition of Selective Non-Catalytic Reduction. This control technology is used for the woodwaste-boilers at Kimberly Clark in Everett, WA, Livermore Falls, ME, and Multitrade in VA. Use of Low-NO<sub>x</sub> Burners and good combustion controls can bring NO<sub>x</sub> emissions down to 0.2-0.3 lb/mmBtu.

SO<sub>2</sub> emissions from the burning of coal could be reduced by 90-95% by installation of a caustic scrubber as at Westvaco in Covington, VA and Fort James in Camas, WA. Caustic is often a waste by-product of the pulp bleaching process and represents an inexpensive source of a scrubbing reagent. Use of low-sulfur (0.5% S) residual oil could reduce SO<sub>2</sub> emissions from oil burning by over 75% (over 110 TPY).

PM<sub>10</sub> emissions from woodwaste boilers are typically controlled to 0.02-0.04 lb/mmBtu by use of 99% efficient electrostatic precipitators. Installation of similar controls on the boiler at

Stone Container would virtually eliminate PM<sub>10</sub> emissions.

Estimates of emission reductions that could be achieved by employing the control technologies discussed above are contained in Table 1.c.

*Lime Kiln* (Emission Unit ID #004) particulate emissions are controlled by a medium-efficiency (80-95%) wet scrubber. TRS emissions from the digesters may also be vented to the kiln for incineration. Emissions in 1997 were estimated by Stone Container at 345 TPY NO<sub>x</sub>, 15 TPY PM<sub>10</sub>, 103 TPY SO<sub>2</sub>, and 11 TPY TRS.

PM emissions could be controlled to 0.03-0.05 grains per dry standard cubic foot (gr/dscf @10% O<sub>2</sub>) (corrected to 10% oxygen) by use of an electrostatic precipitator (ESP). PM emission reductions from venturi scrubbers such as that used at Stone Container could be two to four times greater than reductions from an ESP; scrubbing efficiencies as high as 99% can be achieved by increasing pressure drop and water flow.

TRS emissions can be controlled to 8 parts per million (ppm) by improving the efficiency of the mud washing system to remove addition sulfur compounds.

NO<sub>x</sub> emissions can be controlled to 175-300 ppm through burner design and good combustion techniques.

SO<sub>2</sub> emissions are inherently low due to use of natural gas. However, because TRS is converted to SO<sub>2</sub> by the combustion processes in the kiln, reducing the amount of sulfur introduced into the kiln by improving mud washing efficiency should also result in reduced SO<sub>2</sub> emissions.

*Smelt Dissolving Tank* (Emission Unit ID #020) particulate emissions are controlled by a medium-efficiency (80-95%) wet scrubber. Emissions in 1997 were estimated by Stone Container at 495 TPY NO<sub>x</sub>, 80 TPY PM<sub>10</sub>, 34 TPY SO<sub>2</sub>, and 4 TPY TRS. NO<sub>x</sub> emissions of this magnitude should be explained by Stone Container, as they appear unreasonable.

PM emissions could be better controlled by use of more efficient scrubbers such as those used by Boise-Cascade (in Alabama @ 97.6% control), Gulf States Paper (AL @ 98% control), and Weyerhaeuser (MS @ 99.6% control). TRS emissions can be 85% controlled by improving the efficiency of the wet scrubber. SO<sub>2</sub> emissions can be 70% controlled by improving the efficiency of the wet scrubber.

*Recovery Boiler #1* (Emission Unit ID #001) particulate emissions are controlled by a high-efficiency (95-99.9%) electrostatic precipitator (ESP). TRS emissions from this direct contact evaporator system are controlled through oxidation of the black liquor. Emissions in 1997 were estimated by Stone Container at 311 TPY NO<sub>x</sub>, 162 TPY PM<sub>10</sub>, 1,211 TPY SO<sub>2</sub>, and 26 TPY TRS.

PM emissions should be controlled to 0.03-0.05 lb/mmBtu by the ESP, if total PM<sub>10</sub> is counted. TRS emissions should be limited to 5 ppm by EPA regulations and would likely

require conversion to a non-contact type evaporator. NO<sub>x</sub> emissions in the range of 80-120 ppm should be achievable through good combustion controls. As described in the discussion on Bark Boiler #4, SO<sub>2</sub> emissions can be controlled to around 10 ppm by use of a caustic scrubber; otherwise, emissions of 100-250 ppm should be achievable.

*Recovery Boiler #2* (Emission Unit ID #019) particulate emissions are controlled by a high-efficiency (95-99.9%) ESP. TRS emissions from this direct contact evaporator system are controlled through oxidation of the black liquor. Emissions in 1997 were estimated by Stone Container at 309 TPY NO<sub>x</sub>, 161 TPY PM<sub>10</sub>, 1201 TPY SO<sub>2</sub>, and 34 TPY TRS.

PM emissions should be controlled to 0.03-0.05 lb/mmBtu by the ESP, if total PM<sub>10</sub> is counted. TRS emissions should be limited to 5 ppm by EPA regulations and would likely require conversion to a non-contact type evaporator. NO<sub>x</sub> emissions in the range of 80-120 ppm should be achievable through good combustion controls. As described in the discussion on Bark Boiler #4, SO<sub>2</sub> emissions can be controlled to around 10 ppm by use of a caustic scrubber; otherwise, emissions of 100-250 ppm should be achievable.

*Bark Boiler #3* (Emission Unit ID #015) burns woodwaste that is inherently low in sulfur and ash. The wood fuel is supplemented by also firing high sulfur (2.06% S) residual oil, and clean-burning natural gas. Particulate emissions are controlled by a medium-efficiency (80%-95%) wet scrubber and gravity settling chamber (<80%). Emissions in 1997 were estimated by Stone Container at 351 TPY NO<sub>x</sub>, 48 TPY PM<sub>10</sub>, and 385 TPY SO<sub>2</sub>. Our estimates of these pollutants are contained in Table 1 and Appendices 1 and 4.

NO<sub>x</sub> emissions could be reduced by approximately 40% (to around 0.1-0.2 lb/mmBtu) by addition of Selective Non-Catalytic Reduction as at the woodwaste-boilers at Kimberly Clark in Everett, WA, Livermore Falls, ME, and Multitrade in VA. Use of Low-NO<sub>x</sub> Burners and good combustion controls can bring NO<sub>x</sub> emissions down to 0.2-0.3 lb/mmBtu. Use of low-sulfur (0.5% S) residual oil could reduce SO<sub>2</sub> emissions from oil burning by over 75% (over 110 TPY). PM<sub>10</sub> emissions from woodwaste boilers are typically controlled to 0.02-0.04 lb/mmBtu by use of 99% efficient electrostatic precipitators. Installation of similar controls on this boiler at Stone Container would virtually eliminate PM<sub>10</sub> emissions. Estimates of emission reductions that could be achieved by employing the control technologies discussed above are contained in Table 1.c.

#### Gulf Power-Smith Plant

*Boiler #1* (Emission Unit ID #001) is a tangentially-fired, dry-bottom 150 MW steam-electric generating unit that burns pulverized high sulfur (2.75% S) coal and low sulfur (0.5% S) distillate oil. Particulate emissions are controlled by a high-efficiency (95%-99.9%) ESP. Emissions in 1997 were estimated by Gulf Power-Smith at 3,261 TPY NO<sub>x</sub>, 110 TPY PM<sub>10</sub>, and 22,483 TPY SO<sub>2</sub>. Our estimates of these pollutants are contained in Table 1 and Appendices 2 and 4.

According to the data contained in EPA's Cost Tool model (Appendix 5), this unit emitted NO<sub>x</sub> at a rate of 0.71 lb/mmBtu in 1996. Cost Tool predicts that NO<sub>x</sub> emissions could be

reduced by over 50% (to around 0.33 lb/mmBtu) by addition of close coupled and separated overfire air (LNC3), the same approach used at Unit #2. This approach could reduce NO<sub>x</sub> emissions by over 2,500 TPY at a total annual cost of just under a million dollars, thus yielding a cost effectiveness of \$376 per ton of reduction. LNC3 coupled with Gas Reburn technology could further reduce emissions to 0.17 lb/mmBtu, a reduction of 3,394 TPY at a total cost of \$642/ton. Addition of Selective Non-Catalytic Reduction (SNCR) to LNC3 could achieve 0.20 lb/mmBtu at \$714/ton, while addition of Selective Catalytic Reduction (SCR) could reduce emissions to below 0.10 lb/mmBtu for a total reduction of over 4,000 TPY at less than \$1,000/ton.

SO<sub>2</sub> emissions from the burning of high-sulfur coal could be reduced by 90-95% by installation of a scrubber as is required at new power plants; emission reductions of over 21,000 TPY could be achieved at a total annual cost of \$19 million, or \$830/ton according to EPA's IAPCS5a model (Appendix 6). PM<sub>10</sub> emissions from coal boilers are typically controlled to 0.020 lb/mmBtu by use of 99% efficient electrostatic precipitators.

Estimates of emission reductions that could be achieved by employing the control technologies discussed above are contained in Table 1.c.

Although EPA has not proposed any methods for controlling mercury emissions from coal-fired boilers, application of activated-carbon injection at other combustion sources such as incinerators has been shown to achieve reductions of over 90%. Estimates of emission reductions that could be achieved by employing this control technology are contained in Table 1.e.

*Boiler #2* (Emission Unit ID #002) is a tangentially-fired, dry-bottom 190 MW steam-electric generating unit that burns pulverized high sulfur (2.75% S) coal and low sulfur (0.5% S) distillate oil. Particulate emissions are controlled by a high-efficiency (95%-99.9%) ESP. NO<sub>x</sub> emissions are reduced by an estimated 35% through the use of close coupled and separated overfire air (LNC3). Emissions in 1997 were estimated by Gulf Power-Smith at 2,336 TPY NO<sub>x</sub>, 120 TPY PM<sub>10</sub>, and 24,779 TPY SO<sub>2</sub>. Our estimates of these pollutants are contained in Table 1 and Appendices 2 and 4.

According to the data contained in EPA's Cost Tool model (Appendix 5), NO<sub>x</sub> emissions could be further reduced by over 2,200 TPY (to 0.17 lb/mmBtu) by addition of Gas Reburn at an additional annual cost of \$1.2 million, yielding a total cost effectiveness of \$579 per ton of reduction. Addition of Selective Non-Catalytic Reduction (SNCR) to LNC3 could achieve 0.20 lb/mmBtu @ \$684/ton, while addition of Selective Catalytic Reduction (SCR) could reduce emissions to below 0.10 lb/mmBtu for an additional reduction of almost 1,800 TPY at a total cost of \$689/ton.

SO<sub>2</sub> emissions from the burning of high-sulfur coal could be reduced by 90-95% by installation of a scrubber as is required at new power plants; emission reductions of over 23,000 TPY could be achieved at a total annual cost of \$21 million, or \$820/ton according to EPA's IAPCS5a model (Appendix 6). PM<sub>10</sub> emissions from coal boilers are typically controlled to 0.020 lb/mmBtu by use of 99% efficient electrostatic precipitators.

Estimates of emission reductions that could be achieved by employing the control technologies discussed above are contained in Table 1.c.

Although EPA has not proposed any methods for controlling mercury emissions from coal-fired boilers, application of activated-carbon injection at other combustion sources such as incinerators has been shown to achieve reductions of over 90%. Estimates of emission reductions that could be achieved by employing this control technology are contained in Table 1.e.

*Emission Unit (ID #003)* is described as "Peaking Turbines" and burn low sulfur (0.5% S) distillate oil. Emissions in 1997 were estimated at 14 TPY NO<sub>x</sub>, 0.4 TPY PM<sub>10</sub>, and 7 TPY SO<sub>2</sub>. Our estimates of these pollutants are contained in Table 1 and Appendices 2 and 4.

#### Bay County Energy Systems

*Combustor #1* (Emission Unit ID #001) is a steam-electric generating unit that burns municipal waste, LPG, wood waste, and low sulfur (0.5% S) distillate oil. Particulate emissions are controlled by a high-efficiency (95%-99.9%) ESP. Emissions in 1997 were estimated by Bay County Energy at 58 TPY NO<sub>x</sub>, 6 TPY PM<sub>10</sub>, and 81 TPY SO<sub>2</sub>. Our estimates of these pollutants are contained in Table 1 and Appendices 3 and 4.

*Combustor #2* (Emission Unit ID #002) is a steam-electric generating unit that burns municipal waste, LPG, wood waste, and low sulfur (0.5% S) distillate oil. Particulate emissions are controlled by a high-efficiency (95%-99.9%) ESP. Emissions in 1997 were estimated by Bay County Energy at 71 TPY NO<sub>x</sub>, 23 TPY PM<sub>10</sub>, and 106 TPY SO<sub>2</sub>. Our estimates of these pollutants are contained in Tables 1, 4, and 5.

According to AP-42, NO<sub>x</sub> emissions have been reduced at U.S. municipal waste combustors by approximately 45% by addition of Selective Non-Catalytic Reduction.

In addition to emissions of the criteria pollutants discussed above, the combustion of municipal waste has the potential to emit significant quantities of acid gases, dioxins and furans, and mercury and other heavy metals. Addition of a dry scrubber ahead of the existing ESPs could capture more than 90% of the acid gases and condense the dioxins, furans, and condensable particulate matter so that they could be more easily removed by the ESP. Injection of activated carbon has been employed at other municipal waste incinerators to reduce emissions of mercury, dioxins, and furans, and could remove over 90% of these pollutants at this facility. Estimates of emission reductions that could be achieved by employing the control technologies discussed above are contained in Tables 1.c. and 1.e.

#### **Framework for Atmospheric Deposition Analysis**

The emissions reports do not provide the information required to do an extensive or quantitative analysis of deposition of pollutants from emissions from the three facilities. Detailed

information on source location, stack characteristics, terrain in the modeling domain (watershed), surface roughness, surrounding land use and a representative meteorological data set that included surface and upper air data would be needed for such an analysis. In addition, deposition monitoring information would be useful.

Although such detailed information is not currently available, some general observations can be made from the information provided.

The largest source of both SO<sub>2</sub> and NO<sub>x</sub> that transform into sulfate and nitrate deposition is Gulf Power-Smith, on the shores of North Bay. The chemical transformation from SO<sub>2</sub> to sulfates takes place at a slow rate relative to the area encompassed by the watershed. On a long-term (i.e. annual) basis, the majority of the sulfate will be deposited either directly into the ocean or outside the boundaries of the watershed. Because the three sources are in relative close proximity, the same generalization can be inferred for SO<sub>2</sub> emitted from all three.

The chemical transformation of NO<sub>x</sub> into nitrate occurs at a faster rate than the transformation of SO<sub>2</sub> to sulfates. Therefore, the deposition rate of nitrates into the watershed will be greater than the deposition rate of sulfates. However, because of the location of the sources and the size of the watershed a good portion of the long-term nitrate deposition can be expected to occur over open water or outside the boundaries of the watershed.

Deposition of sulfates and nitrates from rainfall is currently measured at Quincy, Gadsden County (identified as FL14), 110 km northeast of St. Andrew Bay. Deposition is also measured at Sumatra, Liberty County (FL23), 70 km southeast of the bay. Data is available for the Quincy site from the National Atmospheric Deposition Program (NADP) website at:

<http://nadp.sws.uiuc.edu/nadpdata/>

The Sumatra site, formerly a CASTNet site, joined the NADP in February 1999. Data for this site is not yet available from NADP.

Deposition of mercury in rainfall is measured at Chassahowitzka National Wildlife Refuge, 250 km southeast of St. Andrew Bay, as part of the Mercury Deposition Network (MDN). Data can be found on the NADP website at:

<http://nadp.sws.uiuc.edu/nadpdata/mdnsites.asp>

Data from other mercury monitoring sites operated by the Florida Department of Environmental Protection may be more representative of St. Andrew Bay.

In the absence of on-site data, data from these other locations may be used to characterize deposition at St. Andrew Bay. However, it would be preferable to establish deposition monitoring sites near the bay.

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**Table 1.a. St. Andrew's Bay Area Fuel Combustion**

**Solid Fuel Combustion**

**Plant Name**

Boiler Number	Type	Capacity (mmBtu/hr)	(MW)	Type	% S	% Ash	Fuel (mmBtu/SCC Unit)	Annual Use Rate (in SCC Units)	PM Control Type	Efficiency	NOx Control Type	Efficiency
1	PC, tangential, dry bottom		150	Bit coal	2.75	9.73	23.77	452951	ESP			
2	PC, tangential, dry bottom		190	Bit coal	2.75	9.73	23.77	499196	ESP		LNC3	35%
Total (if boilers are similar)			340		2.75	9.73	23.77	952147				

**Plant Name**

Boiler Number	Type	Capacity (mmBtu/hr)	(MW)	Type	% S	% Ash	Fuel (mmBtu/SCC Unit)	Annual Use Rate (in SCC Units)	PM Control Type	Efficiency	NOx Control Type	Efficiency
16	Bark boiler #4			Bark	0	5	7.9	122203	WS	80%		
16	Bark boiler #3			Bark	0	5	7.9	149362	WS	80%		
Total (if boilers are similar)			0		0	5	7.9	271565				

**Plant Name**

Boiler Number	Type	Capacity (mmBtu/hr)	(MW)	Type	% S	% Ash	Fuel (mmBtu/SCC Unit)	Annual Use Rate (in SCC Units)	PM Control Type	Efficiency	NOx Control Type	Efficiency
16	Bark boiler #4			Bit coal	1.07	8.7	28	77610	WS	80%		
Total (if boilers are similar)			0		1.07	8.7	28	77610				

**Plant Name**

Boiler Number	Type	Capacity (mmBtu/hr)	(MW)	Type	% S	% Ash	Fuel (mmBtu/SCC Unit)	Annual Use Rate (in SCC Units)	PM Control Type	Efficiency	NOx Control Type	Efficiency
1	municipal waste combustor			solid waste			9.03	82347	ESP	99%-99.9%		
2	municipal waste combustor			solid waste			9.03	91664	ESP	99%-99.9%		
Total (if boilers are similar)			0		#DIV/0!	#DIV/0!	9.03	174011				

**Fuel Oil Combustion**

Boiler Number	Location	Fuel Input (gal)	%S (mmBtu)	Annual Use Rate (in SCC Units)	PM Control Type	Efficiency	NOx Control Type	Efficiency
16	Stone Container	1344000	2.06	201600				
15	Stone Container	3443500	2.06	516525				
1	Gulf Power-Smith	83670	0.5	11463				
2	Gulf Power-Smith	120740	0.5	16541				
3	Gulf Power-Smith	294550	0.5	40353				
1	Bay County Energy	6860	0.5	940				
2	Bay County Energy	6240	0.5	855				
Total		5299560		788277				

**Table 1.b. St. Andrew's Bay Area Criteria Pollutant Emissions**

Source	Gulf Power—Smith						Stone Container						Bay County Energy		
	Emission Unit	1	2	3	15	16	16	16	1	2	Total				
Fuel	coal	3													
Pollutant	(TPY)	(TPY)	oil	bark	oil	bark	oil	coal	solid waste	solid waste	(TPY)				
Filterable PM-10	119	131	0.8	217	38	177	15	142	total 1 & 2=	9	848				
Filterable PM-2.5	53	58	0.8		38		15	101	total 1 & 2=	9	275				
Total Condensable PM	350	386	0.5		2.6		1.0	66	total 1 & 2=	311	1,116				
Inorganic Condensable PM	280	309			2.2		0.9	52			644				
Organic Condensable PM	70	77			0.4		0.2	13			161				
SO2	23,667	26,083	10.3	0	557	0	217	1,578			52,112				
NOx	3,397	3,744	14.2	112	81	92	32	582			8,054				

**Table 1.c. St. Andrew's Bay Area Criteria Pollutant Emission Reduction Potentials**

Source	Gulf Power—Smith Boilers 1 & 2						Stone Container						Bay County Energy		
	Emission Unit	Current	Proposed	After	Current	Proposed	After	Current	Proposed	After	Reduction	Reduction	Reduction	Reduction	Total
Fuel	Total	Reduction	Reduction	Total	Reduction	Reduction	Total	Reduction	Reduction	Total	(%)	(%)	(%)	(%)	
Pollutant	(TPY)	(TPY)	(%)	(TPY)	(%)	(%)	(TPY)	(%)	(TPY)	(%)					
Filterable PM-10	251	0%	251	589	95%	29	9.0	0%	9	289	559				
Filterable PM-2.5	112	0%	112	154	95%	8	8.0	0%	9	129	147				
Total Condensable PM	736	0%	736	69	95%	3	311.1	0%	311	1,051	66				
Inorganic Condensable PM	588	0%	588	56	95%	3	0.0	0%	0	591	53				
Organic Condensable PM	147	0%	147	14	95%	1	0.0	0%	0	148	13				
SO2	49,760	90%	4,976	2,352	90%	158	0.0	90%	0	5,134	46,979				
NOx	7,155	70%	2,147	898	40%	539	0.0	45%	0	2,686	5,368				

**Table 1.d. St. Andrew's Bay Area Organic Emissions**

Source	Gulf Power-Smith	Stone Container	Bay County	Combined			
Emission Unit	1 & 2	3	15 & 16	16	Energy 1 & 2 solid waste oil	Misc. (1)	Total (lb/yr)
<b>Polychlorinated Dibenzo-P-Dioxins and Polychlorinated Dibenzofurans</b>							
Total PCDD	0.00063		0.0033	0.0033		1.96	1.16E-06
Total PCDF	0.00104		0.0079	0.0156		4.20	4.22
<b>Polynuclear Aromatic Hydrocarbons (PAH)</b>							
Biphenyl	1.62						
Acenaphthene	0.49		1.11	0.04		7.89E-03	1.65
Acenaphthylene	0.24		12.93	0.02		9.46E-05	13.18
Anthracene	0.20		0.90	0.02		4.56E-04	1.11
Benzo(a)anthracene	0.08		0.89	0.01		1.50E-03	0.97
Benzo(a)pyrene	0.04		0.02	0.00			0.06
Benzo(b,j,k)fluoranthene	0.10		7.88	0.01			7.99
Benzo(g,h,i)perylene	0.03		0.38	0.00		8.45E-04	0.41
Chrysene	0.10		0.12	0.01		8.90E-04	0.23
Fluoranthene	0.68		4.97	0.06		1.81E-03	5.70
Fluorene	0.87		0.02	0.07		1.67E-03	0.96
Indeno(1,2,3-cd)pyrene	0.06		0.10	0.00		8.00E-04	0.16
Naphthalene	12.38		920.61	1.01		4.23E-01	934.41
Phenanthrene	2.57		13.63	0.21		3.93E-03	16.42
Pyrene	0.31		4.54	0.03		1.59E-03	4.88
5-Methyl chrysene	0.02						0.02
<b>Various Organic Compounds</b>							
Acetaldehyde	542.72			44.24			586.96
Acetophenone	14.28			1.16			15.45
Acrolein	276.12		1.09	22.51			299.72
Benzene	1237.79		2702.07	100.89		8.00E-02	4040.84
Benzyl chloride	666.50			54.33			720.83
Bis(2-ethylhexyl)phthalate	69.51			5.67			75.17
Bromoform	37.13			3.03			40.16
Carbon disulfide	123.78			10.09			133.87
2-Chloroacetophenone	6.67			0.54			7.21
Chlorobenzene	20.95			1.71			22.65
Chloroform	56.18			4.58			60.76
Cumene	5.05			0.41			5.46
Cyanide	2380.37			194.03			2574.39
2,4-Dinitrotoluene	0.27			0.02			0.29
Dimethyl sulfate	45.70			3.73			49.43
Ethyl benzene	89.50			7.30			96.80
Ethyl chloride	39.99			3.26			43.25
Ethylene dichloride	38.09			3.10			41.19
Ethylene dibromide	1.14			0.09			1.24
Formaldehyde	228.52		2226.83	18.63			2473.97
Hexane	63.79			5.20			68.99
Isophorone	552.25			45.01			597.26
Methyl bromide	152.34			12.42			184.76
Methyl chloride	50.46			4.11			54.58
Methyl ethyl ketone	371.34			30.27			401.61
Methyl hydrazine	161.86			13.19			175.06
Methyl methacrylate	19.04			1.55			20.60
Methyl tert butyl ether	33.33			2.72			36.04
Methylene chloride	276.12			22.51			298.63
Phenol	15.23			1.24			16.48
Propionaldehyde	361.82			29.49			391.31
Tetrachloroethane	40.94			3.34			44.28
Toluene	228.52			18.63		2.32E+00	249.46
1,1,1-Trichloroethylene	19.04			1.55			20.60
Styrene	23.80			1.94			25.74
Xylenes	35.23			2.87		4.08E-02	38.14
Vinyl acetate	7.24			0.59			7.83

(1) See Appendix 4

**Table 1.e. St. Andrew's Bay Area Chlorides, Fluorides, and Heavy Metals Emissions and Potential Reductions**

Source	Gulf Power-Smith			Stone Container			Bay County			Combined			Proposed Reductions		
	1 & 2 coal	3 oil	15 & 16 bark	16 coal	1 & 2 waste	Misc. oil	Total (lb/yr)	Smith (%)	Stone (lb/yr)	Bay County (%)	Total (lb/yr)	Bay County (%)	Total (lb/yr)	Remainder (lb/yr)	
<b>Hydrogen Chloride (HCl) and Hydrogen Fluoride (HF)</b>															
HCl	1,142,576		93,132	105,1026	8.31E-04	2,286,735	90%	1,028,319	90%	83,819	90%	945,924	2,058,061	228,673	
HF	142,822		11,642		8.93E-02	154,464	90%	128,540	90%	10,477	90%	0	139,017	15,446	
<b>Trace Metals</b>															
Antimony	17	4.49E-04	1				19			95%	1		1	17	
Arsenic	390	9.99E-05	23	32	11.95	3.22E-03	457			95%	30		30	427	
Beryllium	20	6.73E-06		2	0.06	1.11E-04	22			95%	2		2	20	
Cadmium	49	8.57E-05	6	4	1.12	9.97E-04	59			95%	4		4	56	
Chromium	248	9.59E-04	42	20		2.07E-03	310			95%	19		19	291	
Chromium (VI)	75		12	6		5.94E-04	94			95%	6		6	88	
Cobalt	95	1.86E-04		8		5.94E-04	103			95%	7		7	98	
Lead	400	1.18E-03	121	33	21.58	3.75E-03	575			95%	31		31	544	
Magnesium	10474	4.69E-03	3422	854			14,749			95%	811		811	13,938	
Manganese	467	6.94E-03		38		7.27E-03	505			95%	36		36	468	
Mercury	79	1.88E-05	1	6	66.03	6.18E-06	143	80%	71	80%	60	122	21		
Nickel	267	2.45E-02	19	22		8.37E-05	307			95%	21		21	286	
Selenium	1238	1.08E-04	12	101	1.33	3.10E-04	1,352			95%	96		96	1,257	

(1) See Appendix 4

**Appendix 1, Table a.**

**Plant Name**      **Stone Container**

Boiler Number	Type	Capacity (mmBtu/hr)	Fuel Type	% S	% Ash	Fuel (mmBtu/SCC Unit)	Annual Use Rate (in SCC Units)	PM Control Type	Efficiency	SO2 Control Type	Efficiency	NOx Control Type	Efficiency
16	Bark boiler #4		Bark	0	5	7.9	122203	WS	80%				
15	Bark boiler #3		Bark	0	5	7.9	149362	WS	80%				
Total (if boilers are similar)		0	0	5	7.9		271565						

**Appendix 1, Table b.****Annual Actual Emissions from Stone Container Bark-Fired Boilers****AP-42 Table 1.6-1. Emission Factors for Particulate Matter (PM),  
Particulate Mater Less than 10 Microns (PM-10),  
and Lead (Pb) from Wood Waste Combustion**

Source	Unit	Emission	Pm	PM-10	Pb	Pm	PM-10	Pb
		Emission Factors (lb/ton)			Emission (TPY)			
Bark boiler #4	16	2.9	2.5	0.00035	177	153	0.021	
Bark boiler #3	15	2.9	2.5	0.00035	217	187	0.026	
Total					394	339	0.048	

**AP-42 Table 1.6-1. Emission Factors for Nitrogen Oxides (NOx),  
Sulfur Oxides (Sox),  
and Total Organic Compounds (TOC) from Wood Waste Combustion**

Source	Unit	Emission	Sox	NOx	TOC	Sox	NOx	TOC
		Emission Factors (lb/ton)			Emission (TPY)			
Bark boiler #4	16	1.5	0.075	0.22	92	5	13	
Bark boiler #3	15	1.5	0.075	0.22	112	6	16	
Total					204	10	29.872	

## Appendix 1, Table c.

AP-42 Table 1.6-4 Emission Factors for Speciated Organic Compounds from Wood Waste Combustion with PM Controls

Pollutant	Emission Factor (lb/ton)	Emissions (lb/yr)
Total PCDD	1.20E-08	0.003
Total PCDF	2.90E-08	0.008
Acenaphthene	4.10E-06	1.11
Acenaphthylene	4.76E-05	12.93
Acetaldehyde	1.92E-03	521.40
Acrolein	4.00E-06	1.09
Anthracene	3.30E-06	0.90
Benzene	9.95E-03	2702.07
Benzo(a)anthracene	3.27E-06	0.89
Benzo(a)pyrene	6.75E-08	0.02
Benzo(b,j,k)fluoranthene	2.90E-05	7.88
Benzo(g,h,i)perylene	1.41E-06	0.38
Chrysene	4.52E-07	0.12
Fluoranthene	1.83E-05	4.97
Fluorene	8.22E-08	0.02
Formaldehyde	8.20E-03	2226.83
Indeno(1,2,3-cd)pyrene	3.60E-07	0.10
Naphthalene	3.39E-03	920.61
Phenanthrene	5.02E-05	13.63
Phenol	1.47E-04	39.92
Pyrene	1.67E-05	4.54

**Appendix 1, Table d.**

**AP-42 Table 1.1-15 Emission Factors for Trace Metals  
from Wood Waste Combustion**

Pollutant	Emission Factor (lb/ton)	Emissions (lb/yr)
Arsenic	8.53E-05	23.2
Cadmium	2.12E-05	5.8
Chromium	1.56E-04	42.4
Chromium (IV)	4.60E-05	12.5
Lead	4.45E-04	120.8
Manganese	1.26E-02	3421.7
Mercury	5.15E-06	1.4
Nickel	6.90E-05	18.7
Selenium	4.59E-05	12.5

**Appendix 1, Table e.**

**Plant Name**      **Stone Container**

Boiler Number	Type	(mmBtu/hr)	Capacity (MW)	Fuel			Annual Use Rate (in SCC Units)		PM Control		SO2 Control		NOx Control	
				Type	% S	% Ash (mmBtu/SCC Unit)	(in SCC Units)	Type	Efficiency	Type	Efficiency	Type	Efficiency	
16	Bark boiler #4			Bit	1.07	8.7	26	77610	WS	80%				
Total (if boilers are similar)			0	1.07	8.7	26	77610							

**Appendix 1, Table f.**

**Annual Actual Emissions from Stone Container Coal-Fired Boilers**

**AP-42 Table 1.1-3. Criteria Pollutant Emissions for Bituminous CoalCombustion (9/98)**

Actual Emissions	SO2			Nitrogen Oxides		
	Emission Factor	Emissions (lb/ton)	(tons)	Emission Factor	Emissions (lb/ton)	(tons)
Location	Boiler					
Bark boiler #4	16	38	1578	15	582	
Total			1,578		582	

**Annual Actual Emissions from Stone Container Coal-Fired Boilers**

**AP-42 Table 1.1-5 Condensable Particulate Matter Emissions for Coal Combustion (9/98)**

Actual Emissions	TOT Condensable PM			TOM Condensable PM			ORG Condensable PM		
	Emission Factor	Emissions (lb/mmBtu)	(tons)	Emission Factor	Emissions (lb/mmBtu)	(tons)	Emission Factor	Emissions (lb/mmBtu)	(tons)
Location	Boiler								
Bark boiler #4	16	0.065	66	0.052	52	0.013	13		
Total			66		52				13

**AP-42 Table 1.1-6 Filterable Particulate Matter Emissions for Coal Combustion (9/98)**

Actual Emissions	Filterable PM-10			Filterable PM-2.5		
	Emission Factor	Emissions (lb/ton)	(tons)	Emission Factor	Emissions (lb/ton)	(tons)
Location	Boiler					
Bark boiler #4	16	0.420	142	0.3	101	
Total			142		101	

**Appendix 1, Table g.**

**AP-42 Table 1.1-12 Emission Factors for Polychlorinated Dibenzo-P-Dioxins and Polychlorinated Dibenzofurans from Controlled Bituminous and Subbituminous Coal Combustion**

Controls	FGD-SDA w FF		
Congener	Emission Factor (lb/ton)	Rating	Emissions (lb/yr)
Total PCDD	4.28E-08	E	0.003
Total PCDF	2.01E-07	E	0.018

**AP-42 Table 1.1-13 Emission Factors for Polynuclear Aromatic Hydrocarbons (PAH) from Controlled Coal Combustion**

Pollutant	Emission Factor (lb/ton)	Rating	Emissions (lb/yr)
Biphenyl	1.70E-06	D	0.13
Acenaphthene	5.10E-07	B	0.04
Acenaphthylene	2.50E-07	B	0.02
Anthracene	2.10E-07	B	0.02
Benzo(a)anthracene	8.00E-08	B	0.01
Benzo(a)pyrene	3.80E-08	D	0.00
Benzo(b,i,k)fluoranthene	1.10E-07	B	0.01
Benzo(g,h,i)perylene	2.70E-08	D	0.00
Chrysene	1.00E-07	C	0.01
Fluoranthene	7.10E-07	B	0.06
Fluorene	9.10E-07	B	0.07
Indeno(1,2,3-cd)pyrene	6.10E-08	C	0.00
Naphthalene	1.30E-05	C	1.01
Phenanthrene	2.70E-08	B	0.21
Pyrene	3.30E-07	B	0.03
5-Methyl chrysene	2.20E-08	D	0.00

**AP-42 Table 1.1-14 Emission Factors for Various Organic Compounds from Controlled Coal Combustion**

Pollutant	Emission Factor (lb/ton)	Rating	Emissions (lb/yr)
Acetaldehyde	5.70E-04	C	44.24
Acetophenone	1.50E-05	D	1.16
Acrolein	2.90E-04	D	22.51
Benzene	1.30E-03	A	100.89
Benzyl chloride	7.00E-04	D	54.33
Bis(2-ethylhexyl)phthalate	7.30E-05	D	5.67
Bromoform	3.90E-05	E	3.03
Carbon disulfide	1.30E-04	D	10.09
2-Chloroacetophenone	7.00E-06	E	0.54
Chlorobenzene	2.20E-05	D	1.71
Chloroform	5.90E-05	D	4.58
Cumene	5.30E-06	E	0.41
Cyanide	2.50E-03	D	184.03
2,4-Dinitrotoluene	2.80E-07	D	0.02
Dimethyl sulfate	4.80E-05	E	3.73
Ethyl benzene	9.40E-05	D	7.30
Ethyl chloride	4.20E-05	D	3.26
Ethylene dichloride	4.00E-05	E	3.10
Ethylene dibromide	1.20E-06	E	0.09
Formaldehyde	2.40E-04	A	18.83
Hexane	6.70E-05	D	5.20
Isophorone	5.80E-04	D	45.01
Methyl bromide	1.60E-04	D	12.42
Methyl chloride	5.30E-05	D	4.11
Methyl ethyl ketone	3.80E-04	D	30.27
Methyl hydrazine	1.70E-04	E	13.19
Methyl methacrylate	2.00E-05	E	1.55
Methyl tert butyl ether	3.50E-05	E	2.72
Methylene chloride	2.90E-04	D	22.51
Phenol	1.60E-05	D	1.24
Propionaldehyde	3.80E-04	D	29.49
Tetrachloroethane	4.30E-05	D	3.34
Toluene	2.40E-04	A	18.63
1,1,1-Trichloroethylene	2.00E-05	E	1.55
Styrene	2.50E-05	D	1.84
Xylenes	3.70E-05	C	2.87
Vinyl acetate	7.60E-06	E	0.59

## **Appendix 1, Table h.**

**AP-42 Table 1.1-15 Emission Factors for Hydrogen Chloride (HCl) and Hydrogen Fluoride (HF)**

Firing Configuration	HCl		HF	
	Emission Factor	Emissions	Emission Factor	Emissions
	(lb/ton)	(lb/yr)	(lb/ton)	(lb/yr)
PC, dry bottom, tangential	1.2	93,132	0.15	11,642

**AP-42 Table 1.1-18 Emission Factors for Trace Metals  
from Controlled Coal Combustion**

Pollutant	Emission Factor (lb/ton)	Emission Factor Rating	Emissions (lb/yr)
Antimony	1.80E-05	A	1.40
Arsenic	4.10E-04	A	31.82
Beryllium	2.10E-05	A	1.63
Cadmium	5.10E-05	A	3.96
Chromium	2.60E-04	A	20.18
Chromium (IV)	7.90E-05	D	6.13
Cobalt	1.00E-04	A	7.76
Lead	4.20E-04	A	32.60
Magnesium	1.10E-02	A	853.71
Manganese	4.90E-04	A	38.03
Mercury	8.30E-05	A	6.44
Nickel	2.80E-04	A	21.73
Selenium	1.30E-03	A	100.89

**Appendix 2, Table a.**

**Plant Name** Lansing Smith

Boiler Number	Type	Capacity (mmBtu/hr)	Fuel			Annual Use Rate (in SCC Units)	PM Control Type	SC2 Control Type	NOx Control Type	Efficiency
			Type	% S	% Ash (mmBtu/SCC Unit)					
1	PC, tangential, dry bottom	150	Bit	2.75	9.73	23.77	452951	ESP		
2	PC, tangential, dry bottom	190	Bit	2.75	9.73	23.77	499196	ESP		
Total (if boilers are similar)		340	2.75	9.73	23.77	952147			LNC3	35%

**Appendix 2, Table b.****Annual Actual Emissions from Gulf Power–Lansing Smith Coal-Fired Boilers****AP-42 Table 1.1-3. Criteria Pollutant Emissions for Bituminous Coal Combustion (9/98)**

Actual Emissions	SO <sub>2</sub>			Nitrogen Oxides	
	Emission Factor	Emissions (lb/ton)	Emission Factor (lb/ton)	Emissions (tons)	Emissions (tons)
Location	Boiler				
Gulf Power–Smith	1	38	23667	15	3397
Gulf Power–Smith	2	38	26083	15	3744
Total		49,750		7,141	

**Annual Actual Emissions from Gulf Power–Lansing Smith Coal-Fired Boilers****AP-42 Table 1.1-5 Condensable Particulate Matter Emissions for Coal Combustion (9/98)**

Actual Emissions	TOT Condensable PM			ORG Condensable PM	
	Emission Factor	Emissions (lb/mmBtu)	Emission Factor (lb/mmBtu)	Emissions (tons)	Emissions (tons)
Location	Boiler				
Gulf Power–Smith	1	0.065	350	0.052	280
Gulf Power–Smith	2	0.065	386	0.052	309
Total			736	588	147

**AP-42 Table 1.1-6. Filterable Particulate Matter Emissions for Coal Combustion (9/98)**

Actual Emissions	Filterable PM-10			Filterable PM-2.5	
	Emission Factor	Emissions (lb/ton)	Emission Factor (lb/ton)	Emissions (tons)	Emissions (tons)
Location	Boiler				
Gulf Power–Smith	1	0.054	119	0.024	53
Gulf Power–Smith	2	0.054	131	0.024	58
Total			250	111	

**Appendix 2, Table c.**

**AP-42 Table 1.1-12 Emission Factors for Polychlorinated Dibenzo-P-Dioxins and Polychlorinated Dibenzofurans from Controlled Bituminous and Subbituminous Coal Combustion**

Controls	ESP or FF		Emissions (lb/yr)
	Emission Factor (lb/ton)	Rating	
Congener			
Total PCDD	6.66E-10	D	0.00063
Total PCDF	1.09E-09	D	0.00104

**AP-42 Table 1.1-13 Emission Factors for Polynuclear Aromatic Hydrocarbons (PAH) from Controlled Coal Combustion**

Pollutant	Emission Factor (lb/ton)	Rating	Emissions (lb/yr)
Biphenyl	1.70E-06	D	1.62
Acenaphthene	5.10E-07	B	0.49
Acenaphthylene	2.50E-07	B	0.24
Anthracene	2.10E-07	B	0.20
Benzo(a)anthracene	8.00E-08	B	0.08
Benzo(a)pyrene	3.80E-08	D	0.04
Benzo(b,j,k)fluoranthene	1.10E-07	B	0.10
Benzo(g,h,i)perylene	2.70E-08	D	0.03
Chrysene	1.00E-07	C	0.10
Fluoranthene	7.10E-07	B	0.68
Fluorene	9.10E-07	B	0.87
Indeno(1,2,3-cd)pyrene	6.10E-08	C	0.06
Naphthalene	1.30E-05	C	12.38
Phenanthrene	2.70E-06	B	2.57
Pyrene	3.30E-07	B	0.31
5-Methyl chrysene	2.20E-08	D	0.02

**AP-42 Table 1.1-14 Emission Factors for Various Organic Compounds from Controlled Coal Combustion**

Pollutant	Emission Factor (lb/ton)	Rating	Emissions (lb/yr)
Acetaldehyde	5.70E-04	C	542.72
Acetophenone	1.50E-05	D	14.28
Acrolein	2.90E-04	D	278.12
Benzene	1.30E-03	A	1237.79
Benzyl chloride	7.00E-04	D	666.50
Bis(2-ethylhexyl)phthalate	7.30E-05	D	69.51
Bromoform	3.90E-05	E	37.13
Carbon disulfide	1.30E-04	D	123.78
2-Chloroacetophenone	7.00E-06	E	6.67
Chlorobenzene	2.20E-05	D	20.95
Chloroform	5.90E-05	D	56.18
Cumene	5.30E-08	E	5.05
Cyanide	2.50E-03	D	2380.37
2,4-Dinitrotoluene	2.80E-07	D	0.27
Dimethyl sulfate	4.80E-05	E	45.70
Ethyl benzene	9.40E-05	D	89.50
Ethyl chloride	4.20E-05	D	39.99
Ethylene dichloride	4.00E-05	E	38.09
Ethylene dibromide	1.20E-06	E	1.14
Formaldehyde	2.40E-04	A	228.52
Hexane	6.70E-05	D	63.79
Isophorone	5.80E-04	D	552.25
Methyl bromide	1.60E-04	D	152.34
Methyl chloride	5.30E-05	D	50.48
Methyl ethyl ketone	3.90E-04	D	371.34
Methyl hydrazine	1.70E-04	E	161.86
Methyl methacrylate	2.00E-05	E	19.04
Methyl tert butyl ether	3.50E-05	E	33.33
Methylene chloride	2.90E-04	D	276.12
Phenol	1.60E-05	D	15.23
Propionaldehyde	3.80E-04	D	381.82
Tetrachloroethane	4.30E-05	D	40.94
Toluene	2.40E-04	A	228.52
1,1,1-Trichloroethylene	2.00E-05	E	19.04
Styrene	2.50E-05	D	23.80
Xylenes	3.70E-05	C	35.23
Vinyl acetate	7.80E-06	E	7.24

**Appendix 2, Table d.****AP-42 Table 1.1-15 Emission Factors**

for Hydrogen Chloride (HCl) and Hydrogen Fluoride (HF)  
from Coal Combustion

Firing Configuration	HCl		HF	
	Emission Factor	Emissions	Emission Factor	Emissions
	(lb/ton)	(lb/yr)	(lb/ton)	(lb/yr)
PC, dry bottom, tangential	1.2	1,142,576	0.15	142,822

**AP-42 Table 1.1-18 Emission Factors for Trace Metals  
from Controlled Coal Combustion**

Pollutant	Emission Factor (lb/ton)	Rating	Emissions (lb/yr)
Antimony	1.80E-05	A	17.1
Arsenic	4.10E-04	A	390.4
Beryllium	2.10E-05	A	20.0
Cadmium	5.10E-05	A	48.6
Chromium	2.60E-04	A	247.6
Chromium (IV)	7.90E-05	D	75.2
Cobalt	1.00E-04	A	95.2
Lead	4.20E-04	A	399.9
Magnesium	1.10E-02	A	10473.6
Manganese	4.90E-04	A	466.6
Mercury	8.30E-05	A	79.0
Nickel	2.80E-04	A	266.6
Selenium	1.30E-03	A	1237.8

**Appendix 2, Table e.**

**Plant Name** Lansing Smith

Boiler Number	Type	Capacity (mmBtu/hr)	(MW)	Fuel			Annual Use Rate (in SCC Units)	PM Control Type	SO2 Control Type	NOx Control Type
				% S	% Ash	(mmBtu/SCC Unit)				
3	Combustion Turbine		#2	0.5		138.5	294.55			
Total (if boilers are similar)		0	0.5	#DIV/0!	138.5	294.55				

**Appendix 2, Table f.**

**Annual Actual Emissions from Gulf Power—Lansing Smith Turbine**

**AP-42 Table 3.1-1. Emission Factors for Large Uncontrolled Gas Turbines**

Actual Emissions	SO <sub>2</sub>		Nitrogen Oxides	
	Emission Factor	Emissions	Emission Factor	Emissions
Location	Boiler (lb/mmBtu)	(tons)	(lb/mmBtu)	(tons)
Gulf Power-Smith	3	1.01	10	0.698
Total		10		14

Actual Emissions	TOT Condensable PM		Filterable PM-10		Filterable PM-2.5	
	Emission Factor	Emissions	Emission Factor	Emissions	Emission Factor	Emissions
Location	Boiler (lb/mmBtu)	(tons)	(lb/mmBtu)	(tons)	(lb/mmBtu)	(tons)
Gulf Power-Smith	3	0.023	0.5	0.038	0.8	0.038
Total		0.5		0.8		0.8

**Appendix 2, Table g.**

**AP-42 Table 3.1-4 Emission Factors for Trace Metals  
from Distillate Oil-Fired Turbines**

Pollutant	Emission Factor (lb/mmBtu)	Emissions (lb/yr)
Antimony	2.20E-05	4.49E-04
Arsenic	4.90E-06	9.99E-05
Beryllium	3.30E-07	6.73E-06
Cadmium	4.20E-06	8.57E-05
Chromium	4.70E-05	9.59E-04
Cobalt	9.10E-06	1.86E-04
Lead	5.80E-05	1.18E-03
Magnesium	2.30E-04	4.69E-03
Manganese	3.40E-04	6.94E-03
Mercury	9.10E-07	1.86E-05
Nickel	1.20E-03	2.45E-02
Selenium	5.30E-06	1.08E-04

**Appendix 3, Table a.**

Plant Name \_\_\_\_\_  
Bay County Energy

Boiler Number	Type	Capacity (mmBtu/hr)	Fuel	Annual Use Rate (in SCC Units)	PM Control Type	SO2 Control Type	NOx Control Type	Efficiency
1	municipal waste combustor		solid waste	9.03	82347	ESP	95%-99.9%	
2	municipal waste combustor		solid waste	9.03	91664	ESP	95%-99.9%	
Total (if boilers are similar)		0	##### #DIV/0!	9.03				174011

### **Appendix 3, Table b.**

#### **Emissions based on EPA FIRE Emission Factors**

Pollutant	Emission Factor (lb/ton)	Emissions (lb/yr)
HCl	6.04	1051026

Pollutant	Emission Factor (lb/ton)	Emissions (lb/yr)
Arsenic	6.87E-05	11.95
Beryllium	3.19E-07	0.06
Cadmium	6.46E-06	1.12
Lead	1.24E-04	21.58
Mercury	3.22E-04	56.03
Selenium	7.63E-06	1.33

Congener	Emission Factor (lb/mmBtu)	Emissions (lb/yr)
Total PCDD	1.25E-06	1.96
Total PCDF	2.67E-06	4.20

	Emission Factor (lb/mmBtu)	Emissions (ton/yr)
PM-condensable	0.396	311
PM-filterable	0.011	9

**Appendix 4, Table 2.**  
Annual Actual Emissions from St. Andrew's Bay Oil-Fired Boilers

**AP-42 Table 1-3-1. Criteria Pollutant Emissions for Fuel Oil Combustion (#81)**

Actual Emissions				SO2		SO3		Nitrogen Oxides		Carbon Monoxide		Filterable PM	
Location	Boiler	Fuel Input (Gal)	%S (mmBtu)	Emission Factor (lb/mmbtu)	Emissions (tons)								
Stone Container	16	1344000	2.06	2016000	157	217.34	5.7	7.891	47	31.58	5	3.38	22
Stone Container	15	3443500	2.06	516525	157	558.65	5.7	20.217	47	80.92	5	8.81	22
Gulf Power-Smith	1	83870	0.5	11463	157	3.28	5.7	0.119	24	1.00	5	0.21	2
Gulf Power-Smith	2	126740	0.5	16541	157	4.74	5.7	0.172	24	1.45	5	0.30	2
Bay County Energy	1	68630	0.5	940	142	0.22	2	0.003	20	0.07	5	0.02	2
Bay County Energy	2	6240	0.5	855	142	0.22	2	0.003	20	0.08	5	0.02	2
Total		5065010		747,924		782.67		28.41		115.09		12.51	
													53.24

Annual Actual Emissions from St. Andrew's Bay Oil-Fired Boilers

**AP-42 Table 1-3-2. Condensable Particulate Matter Emissions for Fuel Oil Combustion (#81)**

Actual Emissions				TOT Condensable PM		ORG Condensable PM		ORG Condensable PM		Emissions		Emissions	
Location	Boiler	Fuel Input (Gal)	%S (mmBtu)	Emission Factor (lb/mmbtu)	Emissions (tons)								
Stone Container	16	1344000	2.06	2016000	1.5	1.01	1.275	0.86	0.225	0.15	0.15	0.225	0.15
Stone Container	15	3443500	2.06	516525	1.5	2.58	1.275	2.20	0.225	0.225	0.39	0.225	0.39
Gulf Power-Smith	1	83870	0.5	11463	1.3	0.05	0.845	0.04	0.045	0.045	0.02	0.045	0.02
Gulf Power-Smith	2	126740	0.5	16541	1.3	0.08	0.845	0.05	0.045	0.045	0.03	0.045	0.03
Bay County Energy	1	68630	0.5	940	1.3	0.004	0.845	0.003	0.045	0.045	0.002	0.045	0.002
Bay County Energy	2	6240	0.5	855	1.3	0.004	0.845	0.003	0.045	0.045	0.001	0.045	0.001
Total		5065010		747,924		3.73		3.14		0.59			

Annual Actual Emissions from St. Andrew's Bay Oil-Fired Boilers

**AP-42 Table 1-3-3. Total Organic Compound Emissions for Fuel Oil Combustion (#81)**

Actual Emissions				Total Organics		Methane		Non-Methane		Emissions		Emissions	
Location	Boiler	Fuel Input (Gal)	%S (mmBtu)	Emission Factor (lb/mmbtu)	Emissions (tons)								
Stone Container	16	1344000	2.06	2016000	1,280	0.860	1,000	0.672	0.188	0.225	0.15	0.225	0.15
Stone Container	15	3443500	2.06	516525	1,280	2.024	1,000	1.722	0.28	0.482	0.39	0.482	0.39
Gulf Power-Smith	1	83870	0.5	11463	1.040	0.044	0.280	0.012	0.76	0.032	0.032	0.032	0.032
Gulf Power-Smith	2	126740	0.5	16541	1.040	0.063	0.280	0.017	0.76	0.046	0.046	0.046	0.046
Bay County Energy	1	68630	0.5	940	0.252	0.001	0.052	0.0002	0.2	0.001	0.001	0.001	0.001
Bay County Energy	2	6240	0.5	855	0.252	0.001	0.052	0.0002	0.2	0.001	0.001	0.001	0.001
Total		5065010		747,924		3,172		2,423		0.749			

Annual Actual Emissions from St. Andrew's Bay Oil-Fired Boilers

**AP-42 Table 1-3-4. N2O, POM & HCOH Emissions for Fuel Oil Combustion (#81)**

Actual Emissions				Nitrous Oxide		Formicdehyde		Emissions		Emissions		Emissions	
Location	Boiler	Fuel Input (Gal)	%S (mmBtu)	Emission Factor (lb/mmbtu)	Emissions (tons)								
Stone Container	16	1344000	2.06	2016000	0.11	11.09	0.0012	0.121	0.042	4.23	4.23	0.042	4.23
Stone Container	15	3443500	2.06	516525	0.11	26.41	0.0012	0.310	0.042	10.45	10.45	0.042	10.45
Gulf Power-Smith	1	83870	0.5	11463	0.11	0.03	0.0013	0.019	0.048	0.048	0.048	0.048	0.048
Gulf Power-Smith	2	126740	0.5	16541	0.11	0.91	0.0033	0.027	0.046	0.046	0.046	0.046	0.046
Bay County Energy	1	68630	0.5	940	0.11	0.05	0.0033	0.001	0.048	0.048	0.048	0.048	0.048
Bay County Energy	2	6240	0.5	855	0.11	0.05	0.0033	0.001	0.048	0.048	0.048	0.048	0.048
Total		5065010		747,924		47.14		0.48		15.80			

Annual Actual Emissions from St. Andrew's Bay Oil-Fired Boilers

**Appendix 4, Table b.**  
Annual Actual Emissions from St. Andrew's Bay Oil-Fired Boilers

**AP-42 Table 1.3-9. Speciated Organic Emissions for Fuel Oil Combustion (#38)**

Actual Emissions			Acenaphthene			Acenaphthyrene			Anthracene			Benzene			Benzofluoranthene		
Location	Fuel Input (GJ)	Emission (nmGal)	Emission Factor	Emissions (ton/yr)	Emission Factor	Emissions (nmGal)	Emission Factor	Emissions (ton/yr)	Emission Factor	Emissions (nmGal)	Emission Factor	Emissions (ton/yr)	Emission Factor	Emissions (nmGal)	Emission Factor	Emissions (ton/yr)	
Stone Container	16	134000	2.08	201600	2.11E-05	2.13E-03	2.53E-07	2.55E-05	1.22E-06	1.23E-04	2.14E-04	2.16E-02	4.01E-06	4.04E-04	1.49E-06	1.49E-04	
Stone Container	15	3443500	2.06	516125	2.11E-05	5.45E-03	2.53E-07	6.32E-05	1.22E-06	3.15E-04	2.14E-04	5.53E-02	4.01E-06	1.04E-03	1.04E-06	3.82E-06	3.82E-04
Gulf Power-Smith	1	63670	0.5	11463	1.11E-05	1.21E-04	2.53E-07	4.55E-06	1.22E-06	6.98E-06	2.14E-04	1.23E-03	4.01E-06	1.73E-03	1.01E-06	6.46E-06	6.46E-03
Gulf Power-Smith	2	120140	0.5	16341	2.11E-05	1.73E-04	2.53E-07	2.09E-06	1.22E-06	1.01E-06	2.14E-04	1.77E-03	4.01E-06	3.32E-03	1.49E-06	1.22E-03	
Bay County Energy	1	8860	0.5	940	2.11E-05	9.92E-06	2.53E-07	1.19E-07	1.22E-06	5.73E-07	2.14E-04	1.01E-04	1.01E-04	1.01E-06	1.01E-06	1.01E-06	1.01E-04
Bay County Energy	2	6240	0.5	655	2.11E-05	9.92E-06	2.53E-07	1.08E-07	1.22E-06	5.73E-07	2.14E-04	1.01E-04	1.01E-04	1.01E-06	1.01E-06	1.01E-06	1.01E-04
Total	5005010	747024	7.99E-03		9.48E-05	9.48E-05	4.56E-04	4.56E-04	8.00E-12	1.50E-03	1.50E-03	5.33E-04					

**Annual Actual Emissions from St. Andrew's Bay Oil-Fired Boilers**

**AP-42 Table 1.3-9. Speciated Organic Emissions for Fuel Oil Combustion (#38)**

Actual Emissions			Chrysene			Dibenzanthracene			Ethylbenzene			Fluoranthene			Fluoranthene		
Location	Boiler	Emission (nmGal)	Emission Factor	Emissions (ton/yr)	Emission Factor	Emissions (nmGal)	Emission Factor	Emissions (ton/yr)	Emission (nmGal)	Emission Factor	Emissions (ton/yr)	Emission (nmGal)	Emission Factor	Emissions (ton/yr)	Emission (nmGal)	Emission Factor	
Stone Container	16	2.26E-06	2.24E-04	2.38E-06	2.40E-04	1.67E-06	1.69E-04	6.34E-05	6.41E-03	4.31E-03	4.31E-03	4.31E-04	4.31E-04	2.14E-06	2.14E-04	2.14E-06	2.14E-04
Stone Container	15	2.26E-06	5.84E-04	2.38E-06	2.40E-04	1.67E-06	1.69E-04	6.34E-05	6.41E-03	4.31E-03	4.31E-03	4.31E-04	4.31E-04	2.14E-06	2.14E-04	2.14E-06	2.14E-04
Gulf Power-Smith	1	2.26E-06	1.30E-05	2.38E-06	1.32E-05	1.87E-06	1.87E-06	6.34E-05	6.35E-03	4.32E-03	4.34E-03	4.34E-04	4.34E-04	2.14E-06	2.14E-03	2.14E-06	2.14E-03
Gulf Power-Smith	2	2.26E-06	1.37E-05	2.38E-06	1.38E-05	1.87E-06	1.87E-06	6.34E-05	6.35E-03	4.32E-03	4.34E-03	4.34E-04	4.34E-04	2.14E-06	2.14E-03	2.14E-06	2.14E-03
Bay County Energy	1	2.26E-06	1.06E-06	2.38E-06	1.07E-06	1.97E-06	1.97E-06	6.34E-05	6.35E-03	4.32E-03	4.34E-03	4.34E-04	4.34E-04	2.14E-06	2.14E-03	2.14E-06	2.14E-03
Bay County Energy	2	2.26E-06	9.68E-07	2.38E-06	1.07E-06	1.97E-06	1.97E-06	6.34E-05	6.35E-03	4.32E-03	4.34E-03	4.34E-04	4.34E-04	2.14E-06	2.14E-03	2.14E-06	2.14E-03
Total			8.45E-04		8.9E-04	6.25E-04		2.36E-02	1.81E-03	1.87E-03		1.87E-03					

**Annual Actual Emissions from St. Andrew's Bay Oil-Fired Boilers**

**AP-42 Table 1.3-9. Speciated Organic Emissions for Fuel Oil Combustion (#38)**

Actual Emissions			Naphthalene			OCDD			Phenanthrene			Pyrene			Trichloroethane		
Location	Fuel	Emissions (nmGal)	Emission Factor	Emissions (ton/yr)	Emission Factor	Emissions (nmGal)	Emission Factor	Emissions (ton/yr)	Emission (nmGal)	Emission Factor	Emissions (ton/yr)	Emission (nmGal)	Emission Factor	Emissions (ton/yr)	Emission (nmGal)	Emission Factor	
Stone Container	18	1.13E-03	1.14E-01	3.19E-09	1.12E-07	1.05E-05	1.08E-03	1.08E-02	1.05E-03	1.01E-03	1.01E-03	1.01E-03	1.01E-03	6.22E-02	6.22E-01	1.01E-02	1.01E-02
Stone Container	18	1.13E-03	2.92E-03	3.19E-09	1.01E-07	1.05E-05	1.07E-03	1.07E-02	1.05E-03	9.71E-04	9.71E-04	9.71E-04	9.71E-04	6.20E-02	6.20E-03	1.01E-02	2.32E-02
Gulf Power-Smith	1	1.13E-03	6.49E-03	1.10E-09	1.10E-07	1.05E-05	6.02E-03	4.25E-06	1.05E-03	2.38E-04	2.38E-04	2.38E-04	2.38E-04	1.35E-03	3.55E-03	1.01E-04	6.35E-04
Gulf Power-Smith	2	1.13E-03	9.35E-03	3.10E-09	2.58E-08	1.05E-05	6.08E-03	4.25E-06	1.05E-03	3.52E-05	3.52E-05	3.52E-05	3.52E-05	1.35E-03	6.20E-03	1.01E-04	6.35E-04
Bay County Energy	1	1.13E-03	5.37E-03	3.10E-09	4.6E-06	1.05E-05	4.93E-06	2.06E-06	1.05E-03	2.38E-04	2.38E-04	2.38E-04	2.38E-04	1.11E-03	6.20E-03	1.01E-04	6.35E-04
Bay County Energy	2	1.13E-03	4.83E-03	3.10E-09	3.33E-09	1.05E-05	4.49E-06	2.25E-06	1.05E-03	2.38E-04	2.38E-04	2.38E-04	2.38E-04	1.01E-03	2.65E-03	1.01E-04	5.12E-05
Total			4.23E-01		1.16E-06		3.9E-03		1.59E-03			8.83E-02		2.32E-02		4.08E-02	

**Annual Actual Emissions from St. Andrew's Bay Oil-Fired Boilers**

**AP-42 Table 1.3-9. Speciated Organic Emissions for Fuel Oil Combustion (#38)**

**Appendix 4, Table C.**  
Annual Actual Emissions from St. Andrew's Bay Oil-Fired Boilers

**AP-42 Tables 1-3-10 & 1-3-11 Trace Element Emissions for Fuel Oil Combustion (\$38)**

Actual Emissions		Antimony		Arsenic		Barium		Beryllium		Cadmium		Chloride		
Location	Boiler	Fuel Input (gai)	% S	Fuel Input (mmBtu)	Emission Factor	Emissions (lb/Kgal)								
Location	Boiler	18	134000	2.08	5.25E-03	3.52E-03	1.32E-03	8.87E-04	2.37E-03	1.73E-03	2.70E-05	1.87E-05	3.98E-04	2.37E-04
Stone Container	15	3443500	2.08	516325	5.25E-03	9.04E-03	1.32E-03	2.27E-03	2.37E-03	4.42E-03	2.70E-05	4.79E-05	8.05E-04	3.47E-04
Gulf Power-Smith	1	83470	0.5	11465				(DE12 Blw)	(DE12 Blw)	(DE12 Blw)	(DE12 Blw)	(DE12 Blw)	(DE12 Blw)	5.97E-04
Gulf Power-Smith	2	120740	0.5	16341					4	2.20E-05		3	1.72E-05	3
Bay County Energy	1	68860	0.5	940					4	3.13E-05		3	2.48E-05	3
Bay County Energy	2	6240	0.5	655					4	1.71E-06		3	1.28E-06	3
Total		5005010		747724						1.28E-02		6.15E-03	3.22E-03	8.31E-04

**Annual Actual Emissions from St. Andrew's Bay Oil-Fired Boilers**

**AP-42 Tables 1-3-10 & 1-3-11 Trace Element Emissions for Fuel Oil Combustion (\$38)**

Actual Emissions		Chromium VI		Cobalt		Copper		Fluoride		Lead		Manganese		
Location	Boiler	Emission Factor (lb/Kgal)	Emissions (tons)											
Location	Boiler	8.45E-04	5.86E-04	2.48E-04	1.87E-04	6.02E-03	4.05E-03	1.76E-03	1.18E-03	3.73E-02	2.51E-02	1.51E-03	1.01E-03	
Stone Container	15	8.45E-04	1.45E-03	2.48E-04	4.21E-04	6.02E-03	1.04E-03	1.76E-03	3.03E-03	3.73E-02	4.21E-02	1.51E-03	3.00E-03	
Stone Container														
Gulf Power-Smith	1	3	1.72E-05					(DE12 Blw)	(DE12 Blw)	(DE12 Blw)	(DE12 Blw)	(DE12 Blw)	(DE12 Blw)	3.17E-03
Gulf Power-Smith	2	3	2.48E-05						6	4.98E-05	6	5.16E-05	6	3.44E-05
Bay County Energy	1	3	1.41E-06						6	2.02E-06	9	7.44E-05	6	4.98E-05
Bay County Energy	2	3	1.20E-06						6	2.56E-06	9	4.23E-06	6	2.82E-06
Total			2.07E-03		5.94E-04		1.44E-02		6	4.30E-03		3.75E-02		7.27E-03

**Annual Actual Emissions from St. Andrew's Bay Oil-Fired Boilers**

**AP-42 Tables 1-3-10 & 1-3-11 Trace Element Emissions for Fuel Oil Combustion (\$38)**

Actual Emissions		Mercury		Molybdenum		Nickel		Phosphorous		Selenium		Vanadium		
Location	Boiler	Emission Factor (lb/Kgal)	Emissions (tons)											
Location	Boiler	16	0	2.92E-08	0	2.03E-07	0	2.11E-05	0	2.41E-06	0	1.70E-07	0	
Stone Container	15	3	1.72E-05		3	1.71E-05			15	8.60E-05	15	8.60E-05	0	
Stone Container														
Gulf Power-Smith	1	3	1.72E-05		3	1.72E-05		(DE12 Blw)	(DE12 Blw)	(DE12 Blw)	(DE12 Blw)	(DE12 Blw)	(DE12 Blw)	4.22E-05
Gulf Power-Smith	2	3	2.48E-05		3	1.72E-05			15	8.60E-05	15	8.60E-05	4	2.28E-05
Bay County Energy	1	3	1.41E-06		3	1.41E-06			15	1.24E-04	15	1.24E-04	4	3.31E-05
Bay County Energy	2	3	1.20E-06		3	1.20E-06			15	7.05E-06	15	7.05E-06	4	1.89E-05
Total			6.19E-05		2.03E-07			6.37E-05		2.44E-06		3.10E-04		8.21E-06

**Annual Actual Emissions from St. Andrew's Bay Oil-Fired Boilers**

**AP-42 Table 1-2-12 CO2 Emissions for Fuel Oil Combustion (\$38)**

Actual Emissions		Carbon Dioxide					
Location	Boiler	Fuel Input (gai)	% S	Emission Factor (mmBtu)	Emissions (tons)	Emission Factor (lb/Kgal)	Emissions (tons)
Stone Container	16	134000	2.08	201800	24400	19377	
Stone Container	15	3443500	2.08	516325	24400	42011	
Gulf Power-Smith	1	83470	0.5	13470	0.5	11463	913
Gulf Power-Smith	2	120740	0.5	16341	0.5	16541	22300
Bay County Energy	1	68860	0.5	940	0.5	940	22300
Bay County Energy	2	6240	0.5	655	0.5	855	22300
Total		5005010		747724		60853	

**Annual Actual Emissions from St. Andrew's Bay Oil-Fired Boilers**

**AP-42 Table 1-2-12 CO2 Emissions for Fuel Oil Combustion (\$38)**

## Appendix C

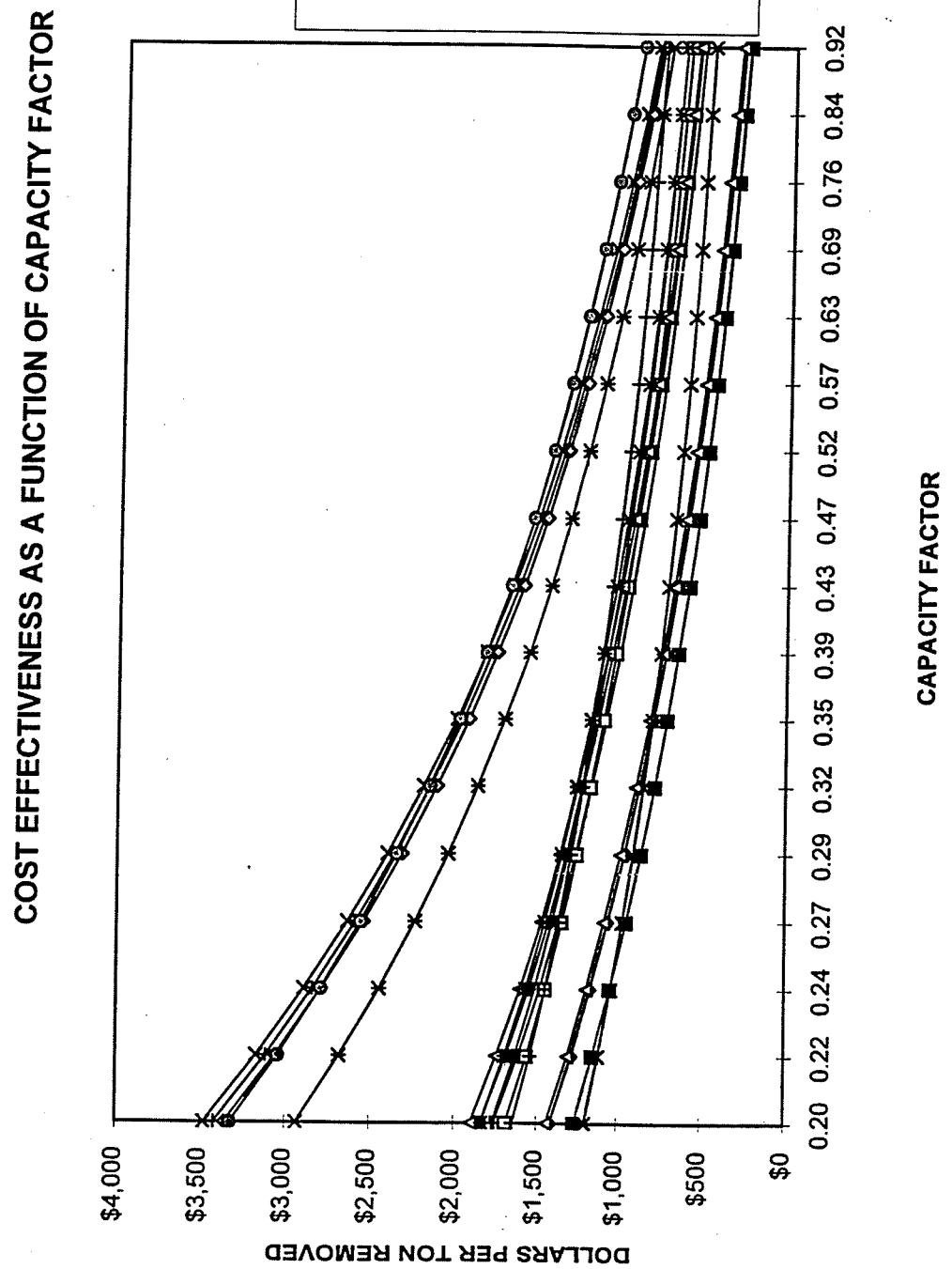
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Plant	LANSINGSMITH
Utility	N/A

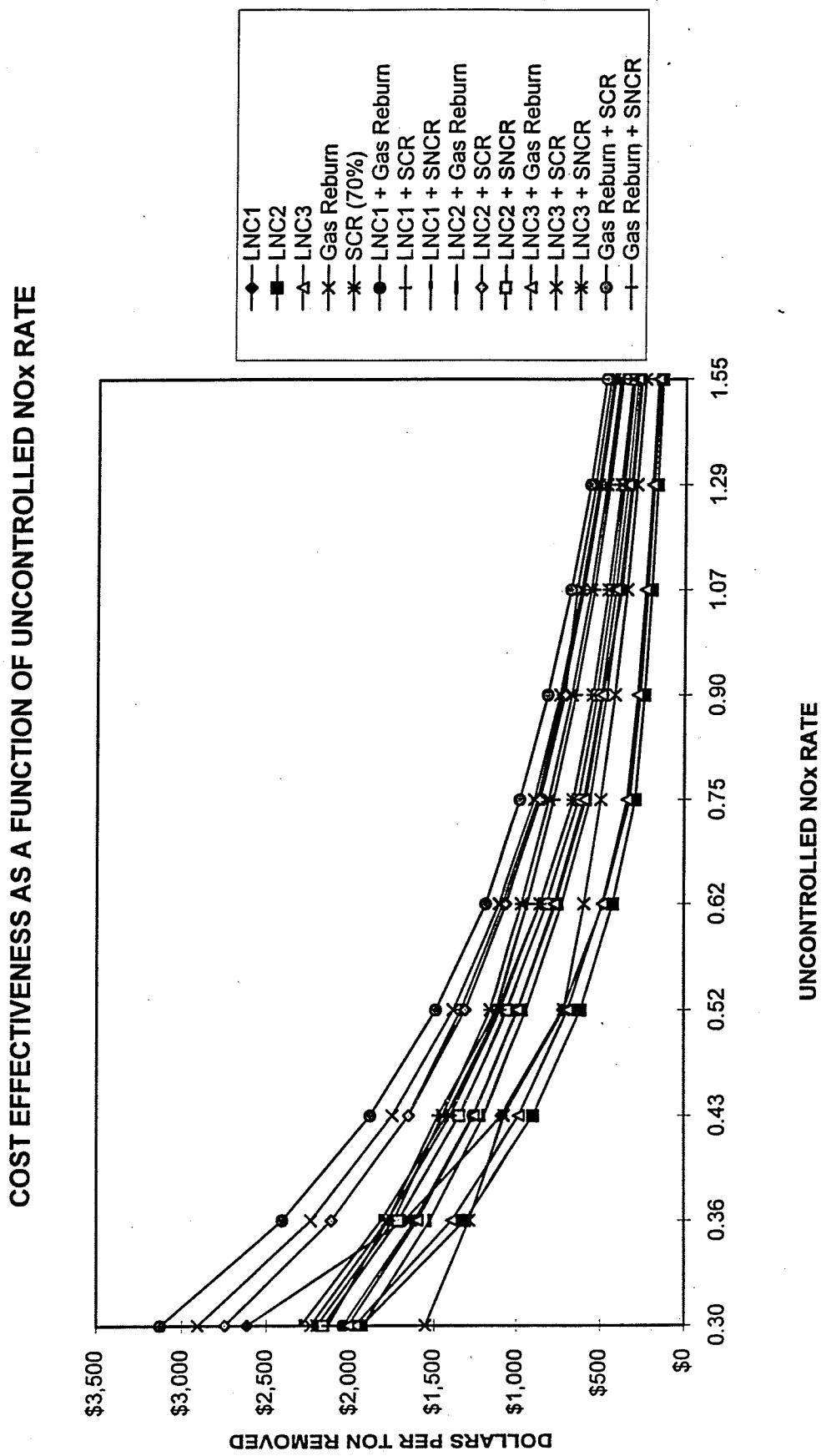
The following combinations of control technologies may be used on tangentially fired boilers.

Click on the button to the right of a particular combination to see detailed results.

Primary Control Technology	Cost Effectiveness	Secondary Control Technology	Cost Effectiveness	Total Cost Effectiveness	New Emission Rate
LNC1	\$360	none	-	\$360	0.41
LNC2	\$323	none	-	\$323	0.37
LNC3	\$376	none	-	\$376	0.33
Gas Reburn	\$523	none	-	\$523	0.36
SCR (70-80%)	\$851	none	-	\$851	0.14
LNC	\$360	Gas Reburn	\$1,449	\$1,449	0.24
LNC2	\$323	Gas Reburn	\$1,260	\$606	0.21
LNC3	\$376	Gas Reburn	\$1,391	\$672	0.17
LNC1	\$360	SCR (70%)	\$1,548	\$931	0.12
LNC2	\$323	SCR (70%)	\$1,697	\$695	0.11
LNC3	\$376	SCR (70%)	\$1,878	\$951	0.10
Gas Reburn	\$523	SCR (70%)	\$1,763	\$1,031	0.11
LNC1	\$360	SNCR (40%)	\$1,374	\$711	0.24
LNC2	\$323	SNCR (40%)	\$1,506	\$680	0.23
LNC3	\$376	SNCR (40%)	\$1,667	\$714	0.20
Gas Reburn	\$523	SNCR (40%)	\$1,564	\$821	0.21

Click on the buttons below to see the cost effectiveness of each combination as a function of capacity factor or uncontrolled NOx rate.



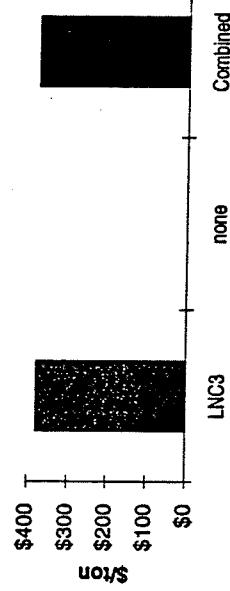


## RESULTS

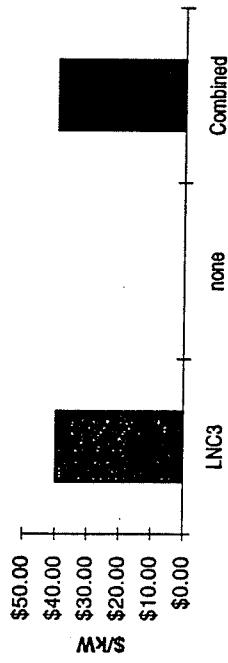
Primary Technology	Secondary Technology	Combined Technologies
LNC3	none	

Capital Cost (\$/kW)	\$39.72	N/A
O&M Cost (mils/kWh)	0.11	N/A
Total Annual Cost (\$)	\$943,977	N/A
Reductions (tons)	2,507	N/A
Cost Effectiveness (\$/ton)	\$376	N/A
New Emission Rate (lbs/mmBtu)	N/A	N/A

Cost Effectiveness (\$/ton)



Capital Cost (\$/kW)

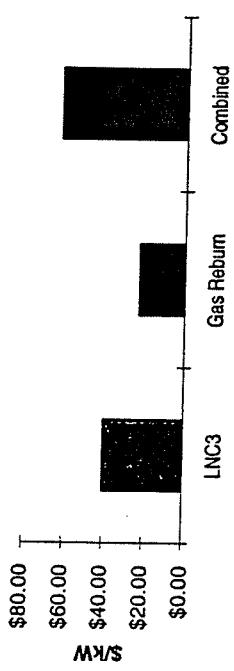


## RESULTS

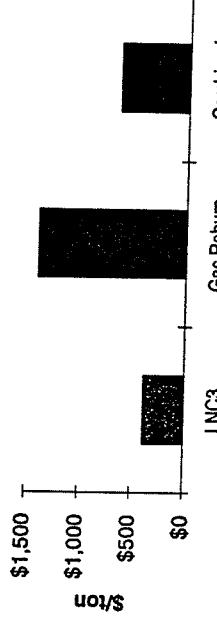
Primary Technology	Secondary Technology	Combined Technologies
LNC3	Gas Reburn	

Capital Cost (\$/kW)	\$39.72	\$22.51
O&M Cost (millis/kWh)	0.11	0.59
Total Annual Cost (\$)	\$943,977	\$1,236,657
Reductions (tons)	2,507	887
Cost Effectiveness (\$/ton)	\$376	\$1,394
New Emission Rate (lbs/mmBtu)	N/A	N/A

Capital Cost (\$/kW)



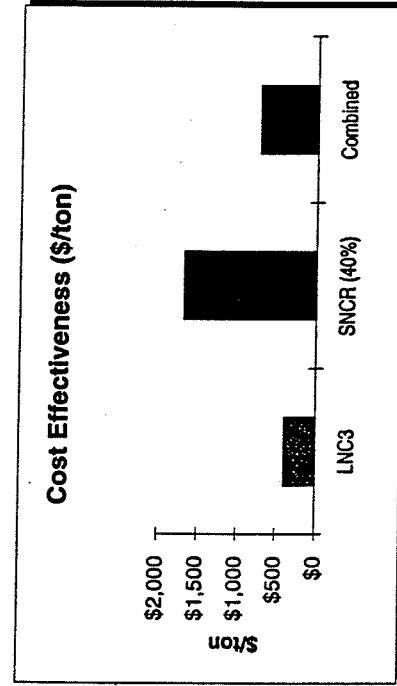
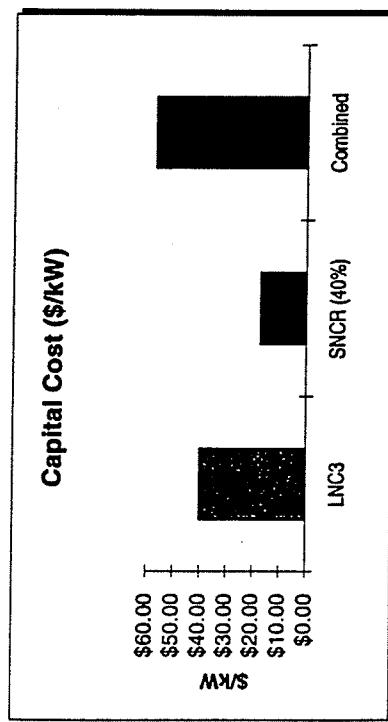
Cost Effectiveness (\$/ton)



## RESULTS

Primary Technology	Secondary Technology	Combined Technologies
LNC3	SNCR (40%)	SNCR (40%)

Capital Cost (\$/kW)	\$39.72	\$16.99	\$57
O&M Cost (mills/kWh)	0.11	0.86	0.97
Total Annual Cost (\$)	\$943,977	\$1,478,203	\$2,422,180
Reductions (tons)	2,507	887	3,394
Cost Effectiveness (\$/ton)	\$376	\$1,667	\$714
New Emission Rate (lbs/mmBtu)	N/A	N/A	0.20

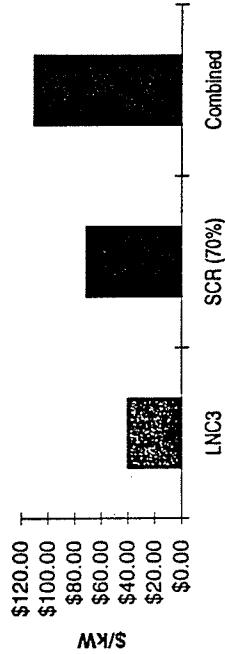


## RESULTS

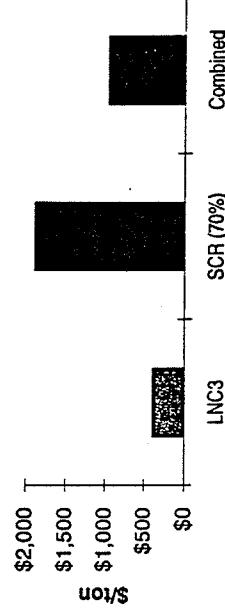
	Primary Technology LNC3	Secondary Technology SCR (70%)	Combined Technologies
--	----------------------------	-----------------------------------	-----------------------

Capital Cost (\$/kW)	\$39.72	\$70.59	\$110
O&M Cost (millis/kWh)	0.11	1.13	1.24
Total Annual Cost (\$)	\$943,977	\$2,915,257	\$3,859,234
Reductions (tons)	2,507	1,552	4,060
Cost Effectiveness (\$/ton)	\$376	\$1,878	\$951
New Emission Rate (lbs/mmBtu)	N/A	N/A	0.10

Capital Cost (\$/kW)



Cost Effectiveness (\$/ton)



ORISPL:	N/A
Boiler ID:	2
Plant:	LANSING SMITH
Utility:	N/A

The following combinations of control technologies may be used on tangentially fired boilers.

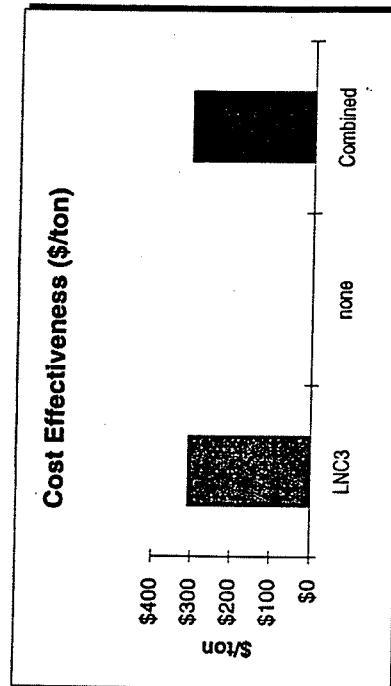
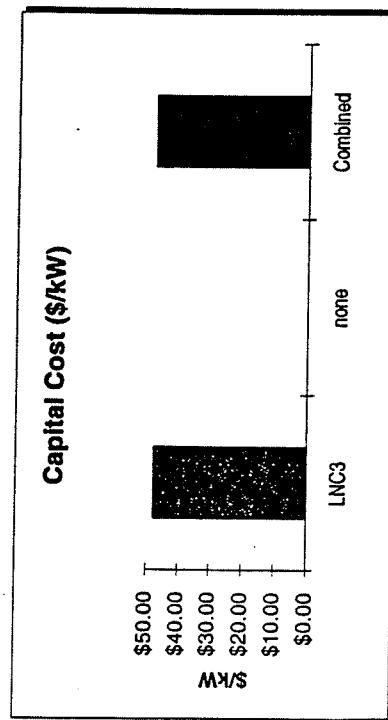
Click on the button to the right of a particular combination to see detailed results.

Primary Control Technology	Cost Effectiveness	Secondary Control Technology	Cost Effectiveness	Total Cost Effectiveness	New Emission Rate
LNC1	\$294	none	-	\$294	0.40
LNC2	\$259	none	-	\$259	0.36
LNC3	\$304	none	-	\$304	0.33
Gas Reburn	\$504	none	-	\$504	0.31
SCR (70-80%)	\$622	none	-	\$622	0.13
LNC1	\$294	Gas Reburn	\$1,004	\$579	0.24
LNC2	\$259	Gas Reburn	\$1,091	\$553	0.21
LNC3	\$304	Gas Reburn	\$1,185	\$579	0.17
LNC1	\$294	SCR (70%)	\$992	\$671	0.12
LNC2	\$259	SCR (70%)	\$1,078	\$658	0.11
LNC3	\$304	SCR (70%)	\$1,183	\$689	0.10
Gas Reburn	\$504	SCR (70%)	\$1,276	\$817	0.10
LNC1	\$294	SNCR (40%)	\$1,292	\$695	0.24
LNC2	\$259	SNCR (40%)	\$1,404	\$663	0.22
LNC3	\$304	SNCR (40%)	\$1,537	\$684	0.20
Gas Reburn	\$504	SNCR (40%)	\$1,620	\$823	0.19

Click on the buttons below to see the cost effectiveness of each combination as a function of capacity factor or uncontrolled NOx rate.

## RESULTS

Primary Technology	Secondary Technology	Combined Technologies
LNC3	none	
Capital Cost (\$/kW)	\$47.46	\$47
O&M Cost (mills/kWh)	0.08	0.08
Total Annual Cost (\$)	\$691,728	\$691,728
Reductions (tons)	2,272	2,272
Cost Effectiveness (\$/ton)	\$304	\$304
New Emission Rate (lbs/mmBtu)	N/A	0.33

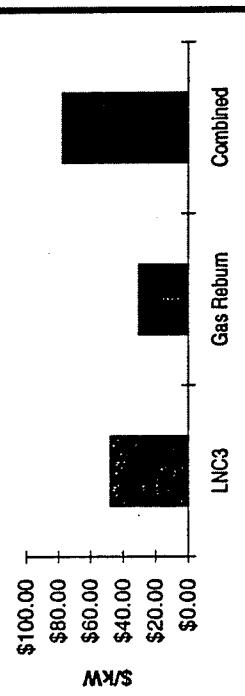


## RESULTS

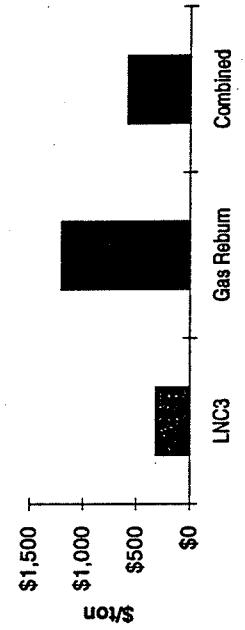
	<b>Primary Technology</b>	<b>Secondary Technology</b>	<b>Combined Technologies</b>
	<b>LNG3</b>	<b>Gas Reburn</b>	
Capital Cost (\$/kW)	\$47.46	\$29.81	\$77
O&M Cost (mills/kWh)	0.08	0.56	0.64
Total Annual Cost (\$)	\$691,728	\$1,209,844	\$1,901,572
Reductions (tons)	2,272	1,013	3,285
Cost Effectiveness (\$/ton)	\$304	\$1,195	\$579
New Emission Rate (lbs/mmBtu)	N/A	N/A	0.17

Capital Cost (\$/kW)  
 O&M Cost (mills/kWh)  
 Total Annual Cost (\$)  
 Reductions (tons)  
 Cost Effectiveness (\$/ton)  
 New Emission Rate (lbs/mmBtu)

Capital Cost (\$/kW)



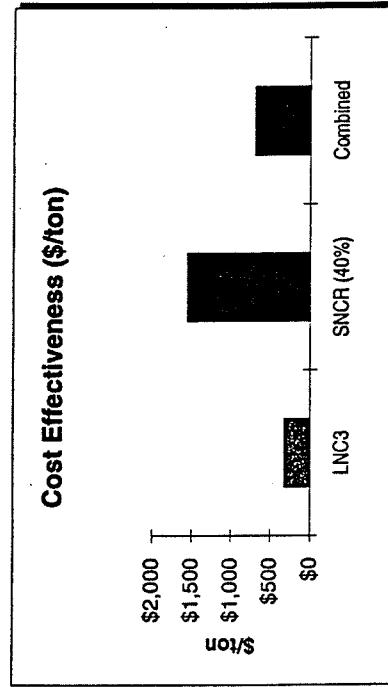
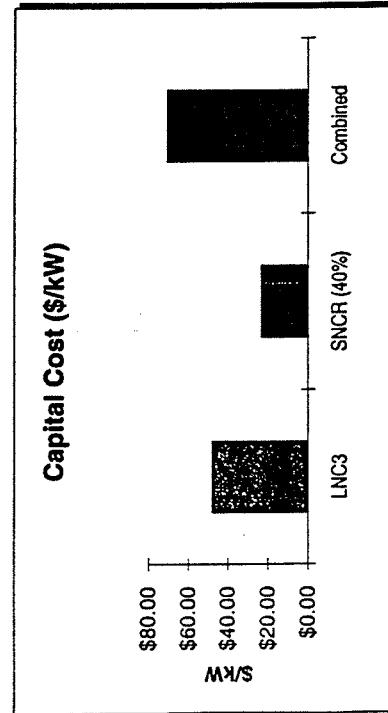
Cost Effectiveness (\$/ton)



## RESULTS

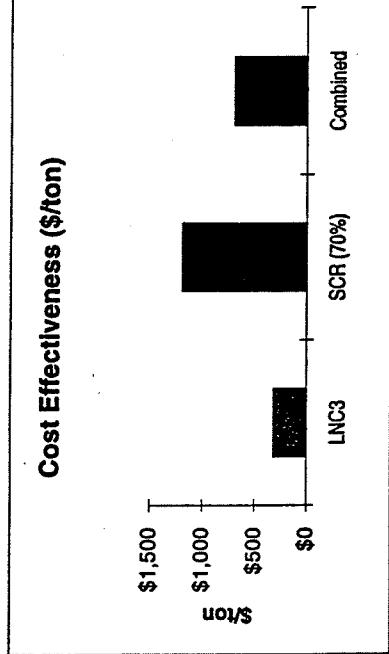
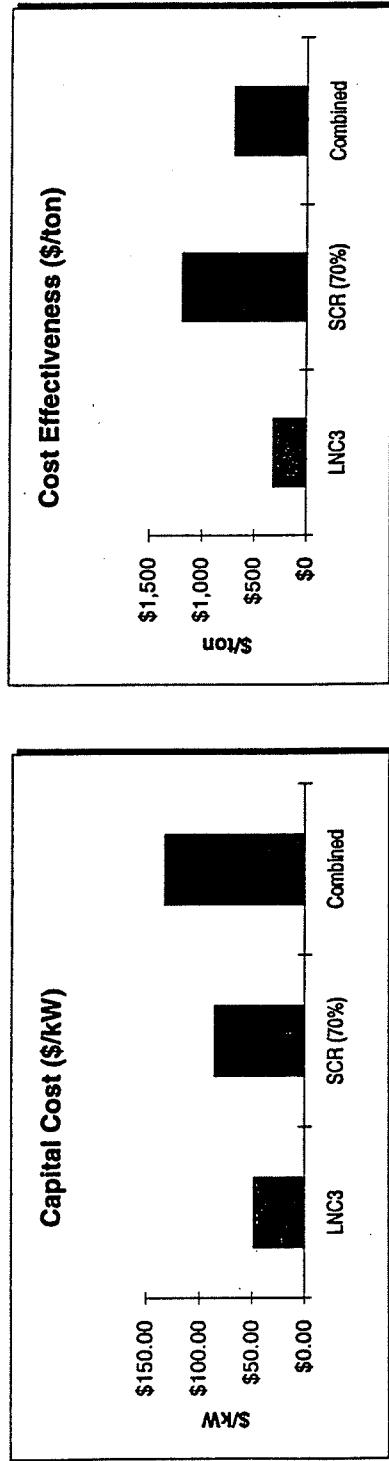
Primary Technology	Secondary Technology	Combined Technologies
LNC3	SNCR (40%)	SNCR (40%)

Capital Cost (\$/kW)	\$47.46	\$22.80	\$70
O&M Cost (milli\$/kWh)	0.08	0.84	0.92
Total Annual Cost (\$)	\$691,728	\$1,556,408	\$2,248,136
Reductions (tons)	2,272	1,013	3,285
Cost Effectiveness (\$/ton)	\$304	\$1,537	\$684
New Emission Rate (lbs/mmBtu)	N/A	N/A	0.20



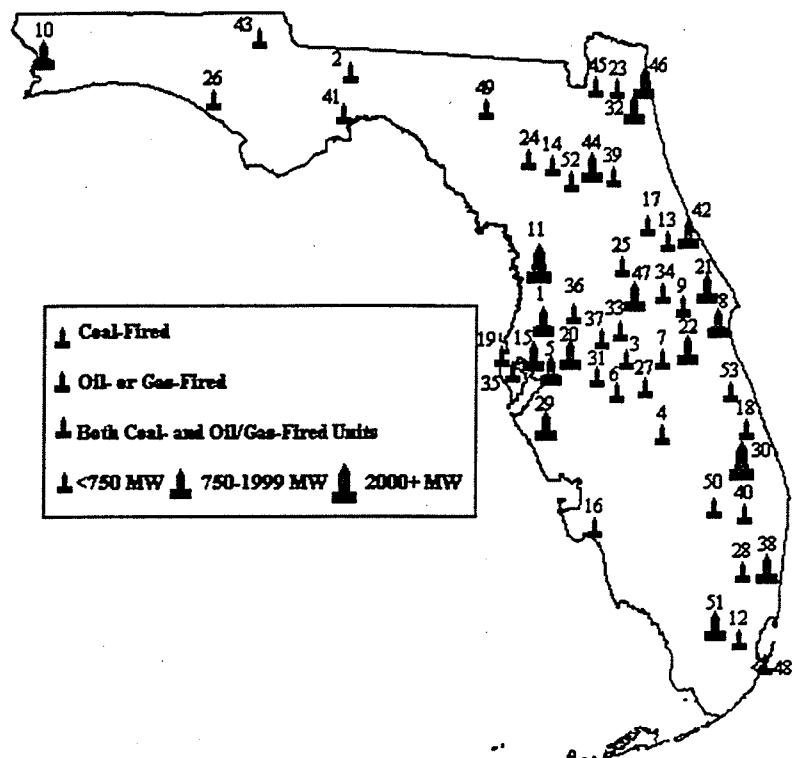
## RESULTS

	Primary Technology LNC3	Secondary Technology SCR (70%)	Combined Technologies
Capital Cost (\$/kW)	\$47.46	\$84.36	\$132
O&M Cost (mills/kWh)	0.08	0.70	0.78
Total Annual Cost (\$)	\$691,728	\$2,092,359	\$2,784,088
Reductions (tons)	2,272	1,769	4,042
Cost Effectiveness (\$/ton)	\$304	\$1,183	\$689
New Emission Rate (lbs/mmBtu)	N/A	N/A	0.10



## Emissions Data for Power Plants

### Florida



View Data For:

Florida Summary

- |                                      |   |
|--------------------------------------|---|
| 1. <u>Anclove</u> (8048)             | 28. <u>Lauderdale</u> (613)             |
| 2. <u>Arvah B Hopkins</u> (688)      | 29. <u>Manatee</u> (6042)               |
| 3. <u>Auburndale Cogen</u> (54658)   | 30. <u>Martin</u> (6043)                |
| 4. <u>Avon Park</u> (624)            | 31. <u>Mulberry Cogen</u> (54426)       |
| 5. <u>Big Bend</u> (645)             | 32. <u>Northside</u> (667)              |
| 6. <u>C D McIntosh Jr</u> (676)      | 33. <u>Orange Cogeneration</u> (54365)  |
| 7. <u>Cane Island</u> (7238)         | 34. <u>Orlando Cogen</u> (54466)        |
| 8. <u>Cape Canaveral</u> (609)       | 35. <u>P L Bartow</u> (634)             |
| 9. <u>Combined Cycle 1</u> (7254)    | 36. <u>Pasco Cogeneration</u> (54424)   |
| 10. <u>Crist</u> (641)               | 37. <u>Polk Power Station</u> (7242)    |
| 11. <u>Crystal River</u> (628)       | 38. <u>Port Everglades</u> (617)        |
| 12. <u>Cutler</u> (610)              | 39. <u>Putnam</u> (6246)                |
| 13. <u>Debary</u> (6046)             | 40. <u>Riviera</u> (619)                |
| 14. <u>Deerhaven</u> (663)           | 41. <u>S O Purdon</u> (689)             |
| 15. <u>F J Gannon</u> (646)          | 42. <u>Sanford</u> (620)                |
| 16. <u>Fort Myers</u> (612)          | 43. <u>Scholz</u> (642)                 |
| 17. <u>G E Turner</u> (629)          | 44. <u>Seminole</u> (136)               |
| 18. <u>Henry D King</u> (658)        | 45. <u>Southside</u> (668)              |
| 19. <u>Higgins</u> (630)             | 46. <u>St Johns River Power</u> (207)   |
| 20. <u>Hookers Point</u> (647)       | 47. <u>Stanton Energy</u> (564)         |
| 21. <u>Indian River</u> (683)        | 48. <u>Stock Island</u> (6584)          |
| 22. <u>Intercession City</u> (8049)  | 49. <u>Suwanee River</u> (638)          |
| 23. <u>J D Kennedy</u> (666)         | 50. <u>Tom G Smith</u> (673)            |
| 24. <u>J R Kelly</u> (664)           | 51. <u>Turkey Point</u> (621)           |
| 25. <u>Lake Cogeneration</u> (54423) | 52. <u>University of Florida</u> (7345) |
| 26. <u>Lansing Smith</u> (643)       | 53. <u>Vero Beach Municipal</u> (693)   |
| 27. <u>Larsen Memorial</u> (675)     |   |

[US Map](#)

[Help](#)

[EPA](#) | [OAR](#) | [Acid Rain Program](#) | [Contact Us](#)

<http://www.epa.gov/acidrain/emission/fl/index1.htm>



## Acid Rain Program

### Plant Summary by Unit

#### Lansing Smith Plant Florida

BOILER ID	BOILER TYPE	FUEL TYPE	NAMEPLATE CAPACITY	PEAKING?	CONTROLS		
					SO <sub>2</sub>	NO <sub>x</sub>	NO <sub>x</sub> INSTALL DATE
1	T	C, G	150	--	U	U	--
2	T	C	190	--	U	LNC3	11/13/1991

T=Tangentially Fired U=Uncontrolled LNC3=Low NOx-Close Coupled&Separated OFA

#### View Data for:

[1995 NOx](#) [1996 NOx](#) [Historic NOx](#) [1996 SO2](#) [1996 CO2](#)

[State Map](#) [US Map](#) [Help](#)

[EPA](#) | [OAR](#) | [Acid Rain Program](#) | [Contact Us](#)

[http://www.epa.gov/acidrain/emission/fl/643\\_sum.htm](http://www.epa.gov/acidrain/emission/fl/643_sum.htm)

# Appendix 6

PAGE 1

IAPCS VERSION 5a

5/ 5/1999

10:46:30

## INTEGRATED AIR POLLUTION CONTROL SYSTEM COSTING PROGRAM-----

Lansing Smith unit #1□  
FGD @ 95%□

### USER INPUT SUMMARY

BOILER SIZE: 150. MW TANGENTIALLY FIRED, DRY BOTTOM  
CAPACITY FACTOR: 82.0 % 310. DEG.F  
CONSTRUCTION STATUS OF CONTROL SYSTEM: RETROFIT

COAL CLEANING LEVEL: RUN-OF-MINE SORTED AND SCREENED  
COAL CHARACTERISTICS AT THIS CLEANING LEVEL:

HHV (BTU/#):11880.0  
SULFUR CONTENT (%): 2.75  
ASH CONTENT (%): 9.73  
COST (\$/TON): .00  
CHLORINE CONTENT (%): .00  
MOISTURE CONTENT (%): 6.00  
VOLATILE MATTER CONTENT (%):36.20  
FIXED CARBON CONTENT (%):48.70

ASH CHARACTERISTICS AT THIS CLEANING LEVEL:

NA2O CONTENT (%): .90  
ALKALINITY (%): 5.10  
FE2O3 CONTENT (%):20.20

CONTROL SYSTEM CONFIGURATION:

1 - FGD

ECONOMIC PREMISES (TVA/EPRI):

EPRI

+  
1

PAGE 2

## INTEGRATED AIR POLLUTION CONTROL SYSTEM COSTING PROGRAM-----

### USER INPUT SUMMARY (CONTINUED)

PARAMETER FILE USED: C:\DONS\POWERP~1\IAPCS\_5A\GPLS1\_FG.EPR

BATCH DATA FILE USED: C:\DONS\POWERP~1\IAPCS\_5A\GPLS1\_FG.EPR

NO CHANGES WERE MADE TO THESE PARAMETER FILES FOR THIS RUN.

1

PAGE 3

FGD

THE CONFIGURATION OF THIS SYSTEM INCLUDES SPRAY TOWERS.

+

LIMESTONE SLURRY.

+

NO CHEMICAL ADDITIVE IS USED.

NO. OF ABSORBERS = 3 , NO. OF SPARE = 0

THE L/G RATIO IS 80.0 @ A STOICHIOMETRIC RATIO OF 1.150.

DESIGN SO<sub>2</sub> REMOVAL OF 95.0% OCCURS IN THE TREATED GAS STREAM.

0.8% OF THE GAS STREAM IS BEING BYPASSED.

0.8% OF THE WASTES ARE DISPOSED OF IN AN ONSITE FACILITY.

FANS

THE TOTAL SYSTEM PRESSURE DROP IS 6.4 IN. H<sub>2</sub>O.

THE SYSTEM REQUIRES 3 FAN(S) RATED AT 239. HP EACH.

1

PAGE 4

BOILER/SYSTEM PERFORMANCE

0

PARASITIC DEMAND (W/O CONTROL) ..... 4.1%

STEAM CYCLE HEAT RATE..... 8277.0 BTU/KWH

BOILER THERMAL EFFICIENCY..... 87.0%

BOILER GROSS HEAT RATE..... 9510.7 BTU/KWH

BOILER NET HEAT RATE W/O CONTROL SYSTEM.. 9922.5 BTU/KWH

BOILER NET HEAT RATE W/ CONTROL SYSTEM... 10086.9 BTU/KWH

HEAT INPUT..... 1488.4 MMBTU/H

COAL USE..... 62.6 TONS/H

ANNUAL COAL CONSUMPTION..... 4.4997E+05 TONS/YR

IAPCS ENERGY PENALTY..... 164.4 BTU/KWH

IAPCS ENERGY PENALTY..... 1.7 %

SYSTEM NET GENERATION..... 147.6 MW

SYSTEM MATERIAL BALANCE  
(100% CAPACITY CONDITION)

AIR

UNCONT- HEATER

ROLLED EXIT

FGD

+

FLUE GAS, 1000 LB/H : 1566. 1566. 1884.  
 FLUE GAS, 1000 ACFM : 520. 520. 464.  
 TEMPERATURE, DEG.F : 310. 310. 127.  
 MOISTURE, LB/H : 85098. 85098. 179353.  
 ALKALINITY, LB/H : 528. 528. 528.  
 PARTICULATE, LB/H : 10362. 10362. 10362.  
 SO<sub>2</sub>, LB/H : 6718. 6718. 336.  
 NO<sub>2</sub>, LB/H : 940. 940. 940.  
 CO<sub>2</sub>, LB/H : 231557. 231557. 231557.

#### EMISSION SUMMARY

POLLUTANT	LB/HR	PERCENT REDUCTION	LB/MMBTU	PPM(V)
PARTICULATE	10362.	.0	6.962	
SO <sub>2</sub>	336.	95.0	.226	81.
NO <sub>2</sub>	940.	.0	.631	482.
CO <sub>2</sub>	231557.	.0	155.577	

1

PAGE 5

INSTALLED CAPITAL COSTS JUNE, 1995

TOTAL WEIGHTED AVERAGE RETROFIT FACTOR: 1.28

FGD-----\$ 25967800

RETROFIT FACTOR: 1.30

MATERIAL HANDLING-----	\$ 1749300
FEED PREPARATION-----	\$ 4373100
GAS HANDLING-----	\$ 3203200
SO <sub>2</sub> SCRUBBING-----	\$ 13136100
OXIDATION-----	\$ 0
REHEAT-----	\$ 0
SOLID SEPARATION-----	\$ 3506100

FANS-----\$ 1717400

RETROFIT FACTOR: 1.00

TOTAL DIRECT CAPITAL COSTS W/O SCOPE ADDERS>>>\$ 27685200  
 TOTAL DIRECT CAPITAL COSTS WITH SCOPE ADDERS>>>\$ 27685200  
 DIRECT COSTS INCLUDE SALES TAX OF .0%

INDIRECT AND STARTUP COSTS-----\$ 20418563

GENERAL FACILITIES (10.0%)	\$ 2768499
ENGINEERING (10.0%)	\$ 2768499
PROJECT CONTINGENCY (34.2%)	\$ 9457499
PROCESS CONTINGENCY ( 1.3%)	\$ 363499
 TOTAL PLANT COST (TPC)	\$ 43043196
INTEREST DURING CONSTRUCTION ( 9.9%)	\$ 2732367
 TOTAL PLANT INVESTMENT ( 3.0yr)	\$ 45775600

ROYALTY ALLOWANCE ( .0%).....\$	0
PREPRODUCTION COSTS ( 5.6%)..\$	1558300
INVENTORY CAPITAL ( 2.8%)....\$	763400
INITIAL CATALYST ( .0%).....\$	0
LAND ( .0%).....\$	6500

1

PAGE 6

**ANNUAL OPERATING COSTS JUNE, 1995**

INFLATION RATE..... 5.0%  
BOOK LIFE ..... 30.0 YEARS  
DISCOUNT RATE..... 11.5%  
DEPRECIATION METHOD..... 3  
1=accelerated, 2=straight line, 3=straightline based on ACRS class

CALCULATED CAPITAL CARRYING CHARGE FACTOR.....0.1655  
CALCULATED O&M LEVELIZATION FACTOR.....1.6116

NOTE: CAPITAL CARRYING CHARGE FACTOR AND O&M LEVELIZATION FACTORS WERE CALCULATED FROM THE ECONOMIC FACTORS LISTED ABOVE AND OTHER FACTORS LISTED IN THE ECONOMIC SECTION.

ITEM	QUANTITY	RATE	ANNUAL COST
=====	=====	=====	=====
OPERATING AND SUPERVISORY LABOR			
+			
SYSTEM	.354E+05 MANHR	25.86 \$/HR	\$ 916000
ANALYSIS	.377E+04 MANHR	26.25 \$/HR	\$ 98900
MAINTENANCE LABOR	.162E+07 \$ .40		\$ 647700
MAINTENANCE MATERIAL	.162E+07 \$ .60		\$ 971600
PERCENT OF TPC = 3.76			
ADMIN. & SUPPORT LABOR	.166E+07 \$ .30		\$ 498800
CONSUMABLES			

+ \_\_\_\_\_  
 SOLIDS DISPOSAL, WET .136E+06 TONS 12.14 \$/TON \$ 1649900  
 WATER .105E+06 K GAL .79 \$/K GAL \$ 82800  
 ELECTRICITY .179E+08 KWH 65.63 mil/KWH \$ 1171600  
 LIMESTONE .432E+05 TONS 19.69 \$/TON \$ 851400  
 0  
 FIXED COMPONENT .150E+06 KWY 20.89 \$/KWY \$ 3133000  
 VARIABLE COMPONENT .108E+10 KWH 3.49 mil/KWH \$ 3755700  
 TOTAL FIRST YEAR O&M EXPENSE  
 LEVELIZED CARRYING CHARGES 48103800 \$ 16.55 % \$ 6888700  
 \$ 7961000  
 BUSBAR COST OF POWER \$ 14849700  
 LEVELIZED FIRST YEAR O&M 6888700 \$ 1.61 \$ 11101800  
 LEVELIZED CARRYING CHARGES 48103800 \$ 16.55 % \$ 7961000  
 LEVELIZED ANNUAL REQUIREMENTS \$ 19062800  
 FIRST YEAR BUSBAR COST OF POWER 13.78 MILLS/KWH  
 LEVELIZED ANNUAL BUSBAR COST OF POWER 17.69 MILLS/KWH  
 COST/TON OF PARTICULATE REMOVED .00 \$/TON  
 COST/TON OF SO2 REMOVED 831.59 \$/TON  
 COST/TON OF NOX REMOVED .00 \$/TON  
 1

PAGE 1

IAPCS VERSION 5a

5/ 5/1999

10:56: 1

INTEGRATED AIR POLLUTION CONTROL SYSTEM COSTING PROGRAM-----  
-----

Lansing Smith unit #2□  
FGD @ 95%□

USER INPUT SUMMARY  
-----

BOILER SIZE: 190. MW TANGENTIALLY FIRED, DRY BOTTOM  
CAPACITY FACTOR: 72.0 % 310. DEG.F  
CONSTRUCTION STATUS OF CONTROL SYSTEM: RETROFIT

COAL CLEANING LEVEL: RUN-OF-MINE SORTED AND SCREENED  
COAL CHARACTERISTICS AT THIS CLEANING LEVEL:

HHV (BTU/#):11880.0  
SULFUR CONTENT (%): 2.75  
ASH CONTENT (%): 9.73  
COST (\$/TON): .00  
CHLORINE CONTENT (%): .00  
MOISTURE CONTENT (%): 6.00  
VOLATILE MATTER CONTENT (%):36.20  
FIXED CARBON CONTENT (%):48.70

ASH CHARACTERISTICS AT THIS CLEANING LEVEL:

NA2O CONTENT (%): .90  
ALKALINITY (%): 5.10  
FE2O3 CONTENT (%):20.20

CONTROL SYSTEM CONFIGURATION:

1 - FGD

ECONOMIC PREMISES (TVA/EPRI):

EPRI

+  
1 PAGE 2

INTEGRATED AIR POLLUTION CONTROL SYSTEM COSTING PROGRAM  
-----

USER INPUT SUMMARY (CONTINUED)  
-----

PARAMETER FILE USED: C:\DONS\POWERP~1\IAPCS\_5A\GPLS2\_FG.EPR

BATCH DATA FILE USED: C:\DONS\POWERP~1\IAPCS\_5A\GPLS2\_FG.EPR

NO CHANGES WERE MADE TO THESE PARAMETER FILES FOR THIS RUN.

1

PAGE 3

FGD

THE CONFIGURATION OF THIS SYSTEM INCLUDES SPRAY TOWERS.

+

LIMESTONE SLURRY.

+

NO CHEMICAL ADDITIVE IS USED.

NO. OF ABSORBERS = 3 , NO. OF SPARE = 0

THE L/G RATIO IS 80.0 @ A STOICHIOMETRIC RATIO OF 1.150.

DESIGN SO<sub>2</sub> REMOVAL OF 95.0% OCCURS IN THE TREATED GAS STREAM.

0.8% OF THE GAS STREAM IS BEING BYPASSED.

0.8% OF THE WASTES ARE DISPOSED OF IN AN ONSITE FACILITY.

FANS

THE TOTAL SYSTEM PRESSURE DROP IS 6.4 IN. H2O.

THE SYSTEM REQUIRES 3 FAN(S) RATED AT 303. HP EACH.

1

PAGE 4

BOILER/SYSTEM PERFORMANCE

0

PARASITIC DEMAND (W/O CONTROL) .....	4.1%
STEAM CYCLE HEAT RATE.....	8277.0 BTU/KWH
BOILER THERMAL EFFICIENCY.....	87.0%
BOILER GROSS HEAT RATE.....	9510.7 BTU/KWH
BOILER NET HEAT RATE W/O CONTROL SYSTEM..	9922.5 BTU/KWH
BOILER NET HEAT RATE W/ CONTROL SYSTEM...	10081.1 BTU/KWH
HEAT INPUT.....	1885.3 MMBTU/H
COAL USE.....	79.3 TONS/H
ANNUAL COAL CONSUMPTION.....	5.0046E+05 TONS/YR
IAPCS ENERGY PENALTY.....	158.6 BTU/KWH
IAPCS ENERGY PENALTY.....	1.6 %
SYSTEM NET GENERATION.....	187.0 MW

SYSTEM MATERIAL BALANCE  
(100% CAPACITY CONDITION)

AIR  
UNCONT- HEATER  
ROLLED EXIT

FGD

+

FLUE GAS, 1000 LB/H : 1984. 1984. 2387.  
 FLUE GAS, 1000 ACFM : 658. 658. 588.  
 TEMPERATURE, DEG.F : 310. 310. 127.  
 MOISTURE, LB/H : 107791. 107791. 227181.  
 ALKALINITY, LB/H : 669. 669. 669.  
 PARTICULATE, LB/H : 13125. 13125. 13125.  
 SO<sub>2</sub>, LB/H : 8510. 8510. 425.  
 NO<sub>2</sub>, LB/H : 1190. 1190. 1190.  
 CO<sub>2</sub>, LB/H : 293305. 293305. 293305.

#### EMISSION SUMMARY

POLLUTANT	LB/HR	PERCENT REDUCTION	LB/MMBTU	PPM(V)
PARTICULATE	13125.	.0	6.962	
SO <sub>2</sub>	425.	95.0	.226	81.
NO <sub>2</sub>	1190.	.0	.631	482.
CO <sub>2</sub>	293305.	.0	155.577	

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INSTALLED CAPITAL COSTS JUNE, 1995

TOTAL WEIGHTED AVERAGE RETROFIT FACTOR: 1.28

FGD-----\$ 28898700

RETROFIT FACTOR: 1.30

MATERIAL HANDLING-----	\$ 1780500
FEED PREPARATION-----	\$ 4543800
GAS HANDLING-----	\$ 3746200
SO <sub>2</sub> SCRUBBING-----	\$ 15095400
OXIDATION-----	\$ 0
REHEAT-----	\$ 0
SOLID SEPARATION-----	\$ 3732700

FANS-----\$ 1953700

RETROFIT FACTOR: 1.00

TOTAL DIRECT CAPITAL COSTS W/O SCOPE ADDERS>>>\$ 30852400  
 TOTAL DIRECT CAPITAL COSTS WITH SCOPE ADDERS>>>\$ 30852400  
 DIRECT COSTS INCLUDE SALES TAX OF .0%

INDIRECT AND STARTUP COSTS-----\$ 22882193

GENERAL FACILITIES (10.0%)	\$	3085199
ENGINEERING (10.0%)	\$	3085199
PROJECT CONTINGENCY (34.1%)	\$	10524900
PROCESS CONTINGENCY ( 1.3%)	\$	404600
TOTAL PLANT COST (TPC)	\$	47952298
INTEREST DURING CONSTRUCTION ( 9.9%)	\$	3043995
TOTAL PLANT INVESTMENT ( 3.0yr)	\$	50996300

ROYALTY ALLOWANCE ( .0%)....\$	0
PREPRODUCTION COSTS ( 5.8%)...\$	1775500
INVENTORY CAPITAL ( 3.1%)....\$	956300
INITIAL CATALYST ( .0%)....\$	0
LAND ( .0%).....\$	6500

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INFLATION RATE..... 5.0%  
 BOOK LIFE ..... 30.0 YEARS  
 DISCOUNT RATE..... 11.5%  
 DEPRECIATION METHOD..... 3  
 1=accelerated, 2=straight line, 3=straightline based on ACRS class

CALCULATED CAPITAL CARRYING CHARGE FACTOR.....0.1655  
CALCULATED O&M LEVELIZATION FACTOR.....1.6116

NOTE: CAPITAL CARRYING CHARGE FACTOR AND O&M LEVELIZATION FACTORS WERE CALCULATED FROM THE ECONOMIC FACTORS LISTED ABOVE AND OTHER FACTORS LISTED IN THE ECONOMIC SECTION.

ITEM	QUANTITY	RATE	ANNUAL COST
=====	=====	=====	=====
OPERATING AND SUPERVISORY LABOR			
+			
SYSTEM	.353E+05 MANHR	25.86 \$/HR	\$ 913900
ANALYSIS	.353E+04 MANHR	26.25 \$/HR	\$ 92700
MAINTENANCE LABOR	.180E+07 \$	.40	\$ 721600
MAINTENANCE MATERIAL	.180E+07 \$	.60	\$ 1082400
PERCENT OF TPC = 3.76			
ADMIN. & SUPPORT LABOR	.173E+07 \$	.30	\$ 518500
CONSUMABLES			

+

SOLIDS DISPOSAL, WET	.151E+06 TONS	12.14 \$/TON	\$ 1835100
WATER	.117E+06 K GAL	.79 \$/K GAL	\$ 92100
ELECTRICITY	.192E+08 KWH	65.63 mil/KWH	\$ 1256900
LIMESTONE	.481E+05 TONS	19.69 \$/TON	\$ 947000
0			
FIXED COMPONENT	.190E+06 KWY	17.52 \$/KWY	\$ 3329100
VARIABLE COMPONENT	.120E+10 KWH	3.45 mil/KWH	\$ 4131100
TOTAL FIRST YEAR O&M EXPENSE			\$ 7460200
LEVELIZED CARRYING CHARGES	53734600 \$	16.55 %	\$ 8892800
BUSBAR COST OF POWER			\$ 16353000
LEVELIZED FIRST YEAR O&M	7460200 \$	1.61	\$ 12022800
LEVELIZED CARRYING CHARGES	53734600 \$	16.55 %	\$ 8892800
LEVELIZED ANNUAL REQUIREMENTS			\$ 20915600
FIRST YEAR BUSBAR COST OF POWER			13.65 MILLS/KWH
LEVELIZED ANNUAL BUSBAR COST OF POWER			17.45 MILLS/KWH
COST/TON OF PARTICULATE REMOVED		.00	\$/TON
COST/TON OF SO2 REMOVED		820.37	\$/TON
COST/TON OF NOX REMOVED		.00	\$/TON

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